REPORT

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2015 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial Time of Use and Critical Peak Pricing Rates

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Prepared for
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Table of Contents

1   Executive Summary

1.1   Introduction

SDG&E's implementation of time varying rates was adopted in decision D-12-12-004 and provides a dynamic pricing option to virtually all of its estimated 116,000 small commercial (i.e., customers with maximum demand less than 20 kW), and 3,400 agricultural customers. Implementation of time varying rates is a significant shift for SDG&E's smaller customers and provides an incentive for reducing consumption during peak periods as well as an opportunity for customers to save on monthly bills by adjusting their behavior. This report estimates the load impacts of time varying rates for small commercial customers voluntarily enrolled during 2015 (ex post) and forecasts load impacts a ten year period which includes the implementation of default time varying pricing in November 2015.

1.2   Small Commercial Opt-in SPP Ex Post Load Impact Summary

Prior to the full-scale implementation of time-varying rates to all non-residential customers, SDG&E offered versions of the SPP rates to a subset of small commercial customers beginning in the summer of 2014. Marketing of SPP rates to small commercial customers was not random, but rather targeted customers who were most likely to benefit from being on one of the two SPP rates and customers with account representatives. Given this marketing strategy, the subset of customers who enrolled on the rates consisted of structural winners who self-selected and are not representative of the entire SDG&E small commercial customer population. This lack of customer diversity further limits the representativeness of the sample to the broader SDG&E population.

Relatively consolidated customer counts, resulting in few independent customer accounts for both TOU and TOU-CPP groups resulted in estimated impacts that were not statistically significant for non-event days. CPP event days also failed to yield significant impacts except on average, where they delivered 0.24MW of load relief.

1.3   Small Commercial Ex Ante Load Impact Summary for Approved SPP Rate

As mentioned in the ex post section of this summary, customers who were on the new TOU and TOU-CPP rates in 2015 were opt-in customers with very different characteristics than the average small commercial customer that will experience a default TOU-CPP or TOU rate. Because of this, it is not appropriate to use the ex post impacts assessed in this report to estimate ex ante impact forecasts. Instead, load impacts for the ex ante portion of this evaluation were estimated using industry-weighted average impacts that were taken from the 2013 PG&E implementation of default TOU rates for small commercial customers. Impacts for CPP event days came from the 2015 evaluation of small commercial customers in the PG&E territory. Due to the uncertainty surrounding the application of another service territory's customer impacts, none of these results are statistically significant.

1.4   Key Findings and Recommendations

Results from the small, voluntary enrollment of small and medium commercial customers in to TOU and TOU-CPP rates failed to yield any significant impacts in the 2015 ex post evaluation. Results

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from the ex-ante portion of this report rely heavily on assumptions made about the similarity of SDG&E small commercial customers to their counterparts in the PG&E territory, as both estimates of TOU and TOU-CPP impacts come from evaluations done there previously.

For future evaluations, it will be difficult, if not impossible, to estimate ex post load impacts unless SDG&E implements the defaulting of customers in stages so there is a period of time when some customers are on the new rates and others are not.

2   Introduction

This report documents the program year 2015 (PY 2015) load impacts for San Diego Gas and Electric's (SDG&E) time varying pricing tariffs for small commercial and agricultural customers, including:

- Time-of-use for small commercial customers (TOU-A);
- Time-of-use with a critical peak pricing component for small commercial customers (TOU-A-P);
- Time-of-use for agricultural customers (TOU-PA); and
- Critical peak pricing for agricultural customers (TOU-PA-P).

Collectively these rates are referred to as time varying rates. With TOU rates (TOU-A, TOU-PA), prices vary according to a preset schedule by season, weekday/weekend and hour of day. With TOU-CPP rates (TOU-A-P and TOU-PA-P), prices also vary according to a preset schedule but customers also face much larger price signals during critical periods, or events, and in exchange get a discount during all other hours. Customers are notified of critical peak events a day in advance.

SDG&E's implementation of time varying rates was adopted in decision D-12-12-004 and provides a dynamic pricing option to virtually its entire estimated 117,000 small commercial (i.e., customers with maximum demand less than 20 kW). Implementation of time varying rates is a significant shift for SDG&E's smaller customers and provides an incentive for reducing consumption during peak periods as well as an opportunity for customers to save on monthly bills by adjusting their behavior. These rates also better reflect the cost producing and delivering electricity.

SDG&E has implemented the rate in two main stages. First, starting in 2014, SDG&E marketed time varying rates exclusively to customers who were expected to experience lower bills.If they enrolled, they did so in a voluntary basis. They were offered a time-of-use (TOU) rate with a preset schedule of prices that vary by season, weekday/weekend and hour of day. In addition, SDG&E offered a similar rate overlaid with a critical peak pricing component (TOU-CPP). With this rate, customers faced a much larger price signal during critical periods, designed to signal the need for larger reductions, and in exchange, received a discount during all other hours. Because of the targeted, voluntary enrollment, customers enrolled in time varying prices during the summer of 2015 were not representative of the broader small commercial and agricultural population. This small, voluntary phase was useful for testing enrollment, dispatch, and communication mechanisms, helping identify improvements and refinements for the much larger implementation of default time varying rates.

Starting in November 2015, all small commercial and agricultural accounts will transition over a six month period to a default CPP rate with an underlying TOU structure (TOU-CPP). Customers can opt-out to a TOU rate without a critical peak pricing component (TOU-A). Starting in 2016, flat rates will no longer be available for small commercial and agricultural customers.

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2.1   Key Research Questions

There are several research questions that will be addressed as part of the evaluation:

1. How comparable are customers enrolled in SPP rates during PY2015 to the general SDG&E small commercial and agricultural population?
2. What is the magnitude of demand reduction from each of the rates during event days (or monthly system peak day for TOU only rates)?
3. Do the SPP rates also lead to energy savings (or increases) during non-event days? What is the magnitude of demand changes for each rate period?
4. Do reductions vary by business type, customer size, load shape, or geography?
5. What steps can be undertaken to improve delivery and performance of SPP rates?
6. What is the magnitude of load reductions forecast for 2016-2026 under 1-in-2 and 1-in10 weather conditions?
7. Did load impacts grow, decay, or remain constant over the course of PY2015?
8. How do impacts vary with temperature, if at all?

2.2   SDG&E's Implementation of Time Varying Rates

Prior to transitioning all customers to time varying rates in the fall of 2015, SDG&E made the rates available to a selected group of small commercial customers on an opt-in basis before the summer of 2014. Customer eligibility for the opt-in rates was determined based on billing analysis and marketing focused on a group of customers who had account representatives and/or were expected to save money compared to their current flat rate.[1] Of the customers who were marketed to, approximately 2,600 enrolled in either the TOU or TOU-CPP rate by the end of 2015, with a roughly even split between the two rates. This report contains an impact analysis of the new rates on these self-selected customers, including impact estimates for summer weekdays when the TOU rate was in effect as well as the four CPP events that were called during the summer (August 28th, and September 9th, 10th and 11th). Customers enrolled in time varying prices during the summer of 2015 were not representative of the broader small commercial and agricultural population. However, this early, voluntary phase was useful for testing enrollment, dispatch, and communication mechanisms, helping identify improvements and refinements for the much larger implementation of default time varying rates.

Table 2-1: SPP Rates and Availability

Customer Segment	Rate	Enrollment Policy		Current Enrollment
		February 1, 2014	November 2015	
Small Commercial*	TOU	Opt in from non-time-varying rate	Default	1,141
	TOU-CPP		May opt out of TOU-CPP and on to TOU	1,468

*Note: Starting in November 2015, flat rates will no longer be available for small commercial and agricultural customers.

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[1] Such customers are sometimes called "structural winners" because the pattern of their existing load shapes would result in monthly bill savings in the absence of any behavioral response to the rate.

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Starting in November 2015, all small commercial accounts will transition over a six month period to a default CPP rate with an underlying TOU structure (TOU-CPP). Customers can opt-out to a TOU rate without a critical peak pricing component (TOU-A). Starting in 2016, flat rates will no longer be available for small commercial and agricultural customers. Table 2-1 summarizes these enrollment policies and the dates of availability for each customer class. The transition from flat to time varying prices along with the accompanying communications to educate customers about when and how to reduce or shift electricity is considered the primary intervention (or treatment). A summary of available rates for the summer of 2015 are shown below in table 2-2.

Table 2-2: SPP Rate Schedules for Summer 2015

Season	TOU/CPP Component	Type of Charge/Credit	Period	TOU-CPP AL-TOU + CPP	TOU AL-TOU	Flat A
Summer	TOU Component	Energy Charges (per kWh)	On-peak	0.13	0.13	0.27
			Semi-peak	0.12	0.12	0.27
			Off-peak	0.09	0.09	0.27
		Demand Charges (per kW)	On-peak	21.40	21.40	-
			Semi-peak	-	-	-
			Maximum	24.43	24.43	-
	CPP Component	Energy Charges and Credits (per kWh)	CPP Event Adder	1.35	-	-
			On-peak	0.00	-	-
			Semi-peak	0.00	-	-
			Off-peak	0.00	-	-
		Demand Credits (per kW)	On-peak	-11.03	-	-
			Semi-peak	-	-	-
Winter	TOU Component	Energy Charges (per kWh)	On-peak	0.12	0.12	0.21
			Semi-peak	0.10	0.10	0.21
			Off-peak	0.08	0.08	0.21
		Demand Charges (per kW)	On-peak	7.66	7.66	-
			Semi-peak	-	-	-
			Maximum	24.43	24.43	-
	CPP Component	Energy Charges and Credits (per kWh)	CPP Event Adder	1.35	-	-
			On-peak	0.00	-	-
			Semi-peak	0.00	-	-
			Off-peak	0.00	-	-
		Demand Credits (per kW)	On-peak	-	-	-
			Semi-peak	-	-	-

2.3 Participant Characteristics

Because of the marketing strategy, it was important to understand the uniqueness of the enrolled service accounts in terms of both demographics and consumption patterns. The participants enrolled during PY2015 are quite distinct from the broader population of small commercial and agricultural customers:

- They were expected to save money compared to their current flat rate even if they did not adjust their behavior and reduce or shift electricity use (structural winners).

- They have unique load shapes and are more likely to have much lower usage during the middle of day than typical small commercial and agricultural customers. They had little load to reduce or shift.

- While the service accounts are small, the customers are large and typically have many small electric service accounts and account representatives.

- Participants are highly concentrated in municipalities and telecommunication industry and in specific end uses. Most are not small, occupied facilities, but rather are sprinkler systems and telecommunication boxes.

The unique nature of the PY2015 participant mix limits the ability to draw conclusions about how the general small business population will respond to time varying pricing, much less about how customers will respond to default time varying pricing. Due to the unusual and limited mix of participation, Nexant recommends against using the 2015 findings to draw broad conclusions about the load impacts or effectiveness of time varying pricing for small commercial and agricultural customers.

Figure 2-1 compares the most common load shapes for participants and non-participants. The top graph summarizes the load shapes, the bottom graph summarizes the proportion of customers in flat, TOU, and TOU-CPP rates categorized into each load shape using k-means cluster analysis. TOU and TOU-CPP participants have a disproportionate share U-shaped of flat loads. The load shape classification was based on average hourly weekday summer loads. Each customers load shape was normalized as the percentage of the daily usage that occurred in that hour. This means all normalized loads, no matter how big or small, add up to 100% and enables classification exclusively based on load shape.

Figure 2-1: 2015 Most Common Load Shapes by Rate Type
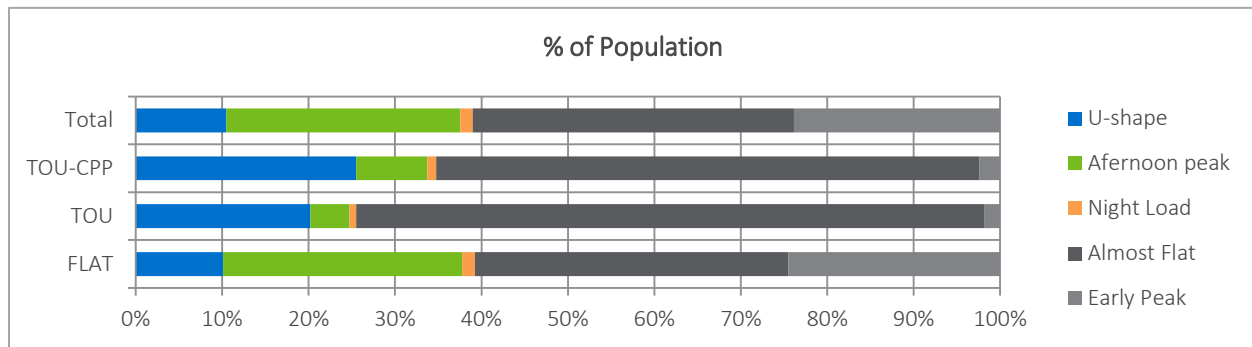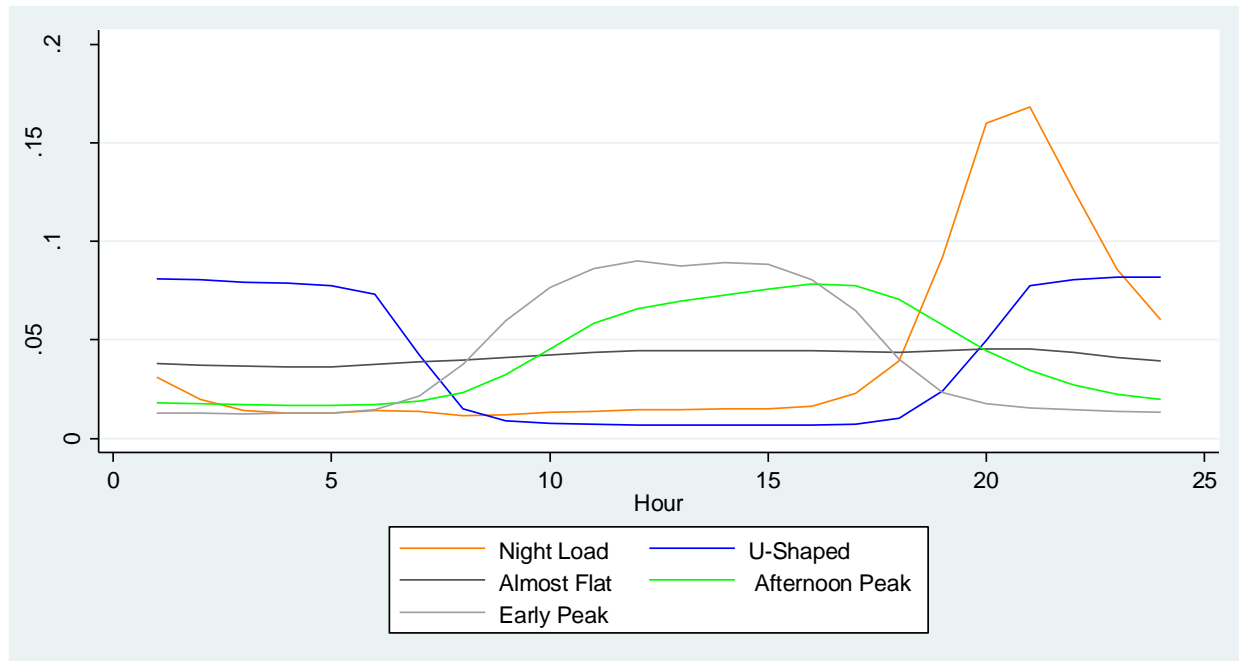
Figure 2-2 highlights the reality that current participating service accounts are linked to relatively few customers with account representatives. Most service accounts are not small, occupied buildings or suites – what we typically imagine as small business – but rather small electric accounts across with coordinated, centralized management across numerous sites. In the general population, less than 0.4% of customers have 20 or more accounts and they jointly own 12.5% of the overall population of service accounts. Among the TOU group, 7.8% of customers have 20 or more accounts and they jointly own 53.3% of all TOU accounts. Ownership of service accounts is even more concentrated for the TOU-CPP rates – 2.6% of customers have 20 or more accounts and they own 54% of all TOU-CPP accounts.

Figure 2-2: Participants are Associated with Few Customers with Multiple Accounts
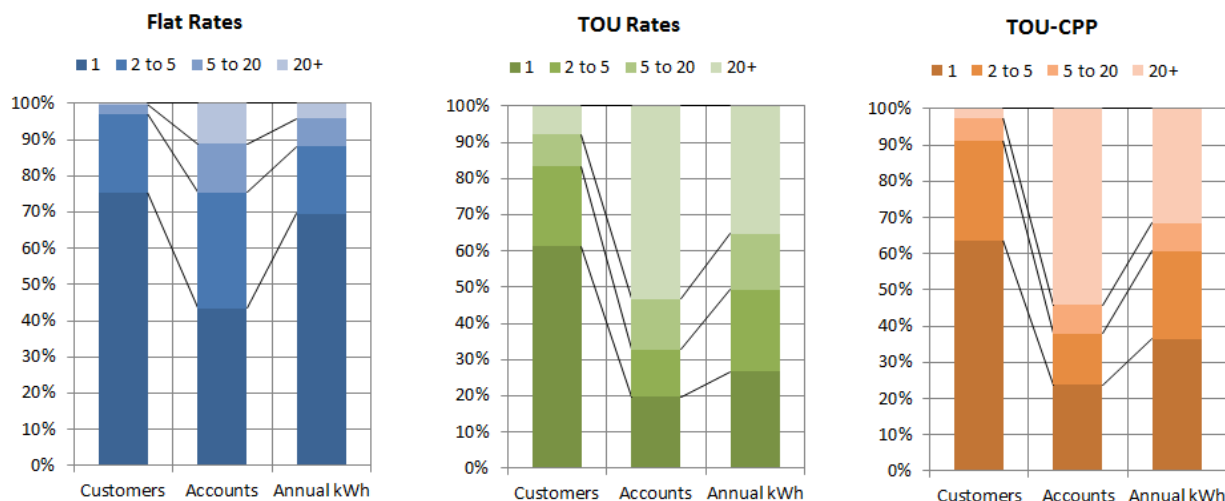
2.4   Study Challenges and Limitations

The unique nature of the PY 2015 participant group has several implications and poses several challenges that dictate the evaluation approach. Due to the unusual and limited mix of participants, we recommend against using the 2015 findings to draw broad conclusions about the load impacts or effectiveness of time varying pricing for small commercial and agricultural customers. It also has important methodological implications – namely fewer control candidates are suitable and careful attention was required in estimating confidence intervals because the individual service accounts are not independent observations.

2.5   Report Organization

The remainder of this report is organized as follows. Section 3 describes the ex post evaluation design and the methods used to calculate impact estimates for summer weekdays and CPP event days. Section 4 presents the ex post load impact results for the opt-in TOU rates that were marketed to select small commercial customers. Section 5 describes the ex post load impacts for non-event days and CPP days for TOU-CPP customers. Section 6 summarizes the ex ante estimation methodology for TOU and TOU-CPP customers, and section 7 summarizes the results of the ex ante estimation. The report concludes with specific recommendations for future evaluations in section 8.

3   Evaluation Design and Methodology

To estimate load impacts, it is necessary to estimate what energy consumption would have been in the absence of TOU and CPP-TOU rates:the counterfactual or reference load. The key challenge of evaluation is attribution. Did the introduction of TOU and CPP-TOU rates cause a decrease in electricity consumption during peak periods when prices were higher or can the differences in peak period electricity use be explained by other factors? To infer that TOU prices changed electricity use patterns, one must be able to systematically eliminate plausible alternative explanations for differences in electricity use patterns, including random chance.

The effect of PY2015 voluntary enrollment of SPP rates on small commercial and agricultural customers was analyzed through difference-in-differences, using a control group that is developed via iterative propensity score matching.[2]

Nexant first selected an applicable control group from customers who remained on flat rate tariffs via statistical matching. By matching on pretreatment interval data, we select control customers with similar observable characteristics to our treatment group, and make the assumption that this will remove or mitigate unobserved differences between the groups as well. This implies that any observed difference usage or load shape in the period after the treatment group has gone on time-varying rates is due to the effect of treatment, minimizing the selection effect of voluntary enrollment

Difference-in-differences helps produce more precise estimates and can correct for unobserved differences (should they exist). While the analysis is implemented using a panel regression with fixed effects, time effects, and additional explanatory variables, the underlying concept is simple:

- Measure energy demand patterns for both the treatment and control groupswhile all customers are on flat rates. This requires using data from the 2013-2014 timeframe. Since SPP rates were not in place and, thus, were not influencing behavior any differences between the treatment and control group are pre-existing and not due to TOU rates.

- Measure energy demand patterns after implementation of time varying rates. If there is an effect, we should see a change among customers that transitioned to time varying rates but no similar change for customers that remained on flat pricing (the control group).

- Net out any pre-existing differences between the TOU groups. This step leads to more precision and also helps control for any unobserved differences between the two groups that are related to when and how much energy customers consume.

The effect of treatment is calculated by taking difference between the treatment and matched control group in the post period and subtracting any difference between the groups in the pre-treatment period.

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[2] The ability to implement the analysis via regression discontinuity, a type of local experiment, was also carefully assessed. Unfortunately, the cutoff for customers who were not placed on TOU was not based on a continuous date rollout but rather based on bulk transition of customers to PG&E's smart meter web portal.

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3.1   Enrollment and Treatment Timing of Treatment Customers

Marketing and enrollment for the TOU and TOU-CPP SPP rates began early in the summer of 2014. The number of enrolled customers in each rate as a function of time is presented in Figure 3-1. Enrollment in the TOU rate saw an initial jump at the beginning of July 2014, followed by more gradual growth for the remainder of the enrollment period. For the TOU-CPP rate, the initial jump in enrolled customers was smaller, but was followed by faster growth during the remainder of the summer and fall, with a secondary enrollment period in the winter of 2014-2015. In order to analyze the same group of customers throughout the entire summer, cutoffs were established to determine which customers would be included in the ex post analysis dataset. The analysis group included the 2,609 customers who enrolled prior to January 1st, 2015, so that the analysis dataset consisted of January through October.

Figure 3-1: Enrollment in Opt-in SPP Rates by December 2015
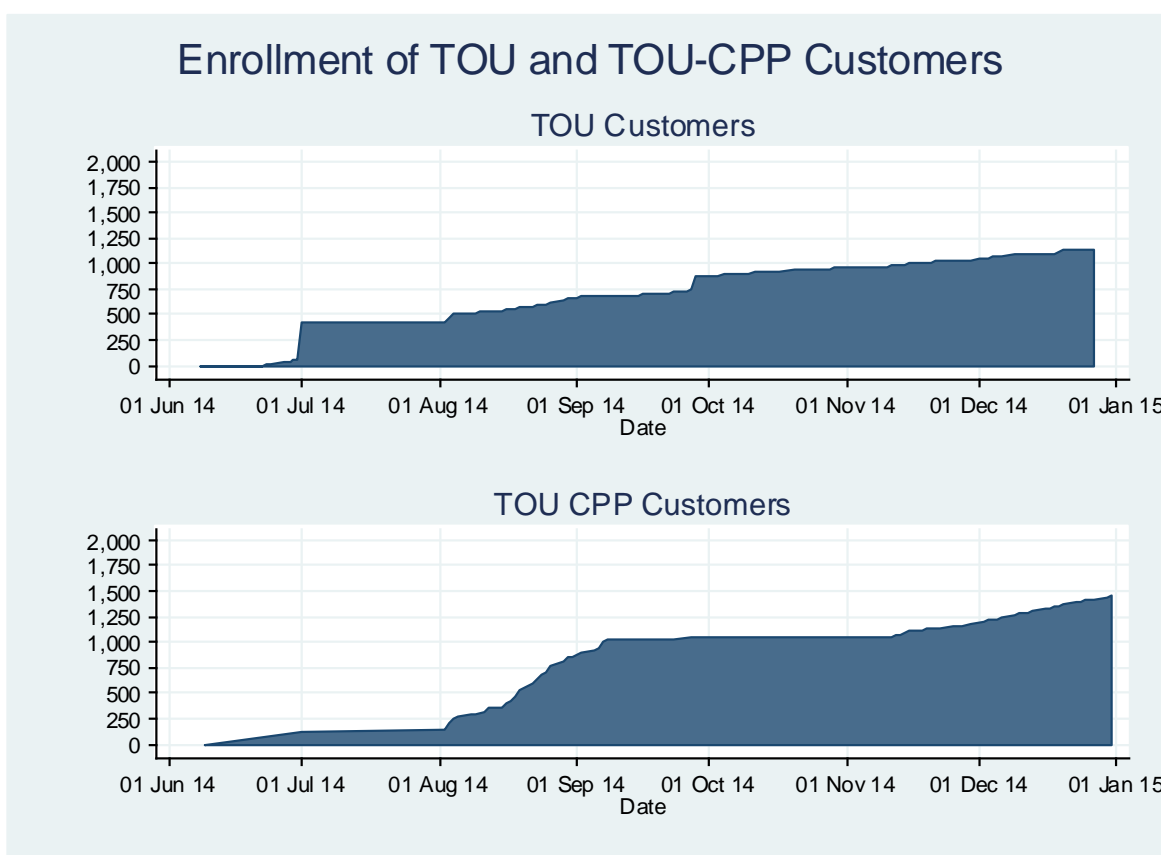
3.2   Selection of Matched Control Groups

The customers who opted in to time-varying rates are not reflective of the overall small commercial population. These customers were specifically marketed to with information about the new rates, and were likely to experience bill reductions as a result of adopting these rates. As discussed in the introduction, due to the uniqueness of the enrolled customers, a suitable control group does not exist and must be constructed using statistical matching. A specific benefit of control groups for the purpose of evaluating CPP rates is that they tend to work even when all of the hottest days are event days. They do not require extrapolating from hot days to extremely hot days because we can observe the control group during actual event conditions. The results also do not depend on the functional form of a regression specification but rather on the similarity of the control and TOU-CPP groups, which can be explicitly assessed using pre-enrollment data.

Since customers were not randomly assigned to the new rates, it is possible that they had particular characteristics that made them more likely to enroll than those who stayed on the flat rate. This type of behavior introduces selection bias in to any estimate of the impact of time-varying rates, because the difference in load profile or usage between treatment and control that are actually due to the inherent difference between the groups could mistakenly be attributed to the impact of treatment. To counteract this selection effect, Nexant matched customers who opted in to the time-varying rates (treatment) with customers that remained on the flat rate (control) based on the similarity of their pretreatment characteristics, including load shapes, summer and winter average usage, and industry. Matching makes the assumption that removing observable differences between treatment and control customers will also reduce or eliminate differences in unobservable characteristics that could lead to selection bias in estimating the impact of treatment.

Statistical matching involves using a probit model to estimate a propensity score for each treatment customer and control candidate. In this model specification, observed characteristics, such as industry category, load profile, and bins of annual usage are explanatory variables that are used to predict whether or not a particular customer enrolled in the treatment or not. The output of this probit model are propensity scores for each customer indicating how likely they are to be in the treatment group, given their characteristics. Matching is conducted by selecting a pair of customers with similar propensity scores; one of which enrolled in the time-varying rates and one that remained on the flat rate. When done successfully, the difference between the treatment and match-controlled group on the matching variables should be statistically indistinguishable.

Nexant performed this matching process separately for customers on the TOU rate and the TOU-CPP rate, and used customers on the comparable flat rates as the control pool candidates. Only pre-treatment usage data and other characteristics were used to ensure the treatment and control customers had as little difference as possible in their load shapes and usage prior to implementation of a time-varying rate. The customers were matched based on industry, average summer and winter load, and clustered load shape.

Matching was conducted using an iterative process whereby ten candidate control customers were matched for each treatment customer on industry, load shape cluster, and average

summer and winter load profiles constructed with 50% of available pre-treatment interval data, referred to as the in-sample pretreatment data.

The match quality was further refined for each candidate by using a multi-step process to identify a control group that maximized goodness of fit while minimizing any bias:

1. For each treatment customer and group of ten control candidates, select the control candidate that minimizes the root mean squared error (RMSE) of the in-sample interval data compared to the treatment customer.

2. Keep the control customer with the lowest RMSE, and then bring in the out of sample pretreatment interval data which has been held out of the matching process so far.

3. Select the match cohort, out of the ten available with winning candidates from stage two that on average minimized that average percent error (MPE) on the out of sample days.

Two statistics were calculated to represent the performance of each model during the holdout period, with formulas shown below. The average percent error is a measure of bias, indicating how much higher or lower, on average, the treatment group's usage is compared to that of the control group. The root mean squared error, however, is a measure of goodness of fit. It gives an indication of the magnitude of the difference between the treatment and control load profiles on average, but does not measure the direction (the bias) of the two load shapes. By picking a control group that minimizes both the bias and average error, the control groups' load shape will be as close as possible to both the shape and magnitude of the treatment groups' profile.

- Average Percent Error $= APE = \dfrac{\sum kWh_{treat}}{\sum kWh_{control}} - 1$

- Root Mean Squared Error $= RMSE = \sqrt{\sum_{i=1}^{N}(kWh_{treat,i} - kWh_{control,i})^2 \big/ N}$

Successful implementation of a matched control group requires that there be sufficient numbers of control candidates to be able to match every treatment customer on the desired characteristics. Depending on how irregular the load profile of any treatment group customer may be, a suitable match may not be found for them. Matching within customer segments with small numbers of control customers may also have this effect, requiring careful examination of the percent of treatment customers that were successfully matched in order to assess the quality of the process. Roughly 88% of TOU customers and 92% of TOU-CPP customers had sufficient data to be included in the full analysis. However, the quality of the matching process overall was quite good, with only 66 treatment customers not being matched out of 2983, or 2%.

The goal of statistical matching is to eliminate preexisting differences between a treatment and a constructed control group by picking from a large pool of control customers only those that are similar to the treatment group. If done successfully, the resulting control group will be statistically indistinguishable from the treatment group in the pretreatment period. Load profiles, such as the ones shown below in Figure 3-2 show the results of the matched control group; the

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load profiles are nearly identical, with an average difference between treatment and control of less than 1%.

Figure 3-2: Average Summer Weekday Loads for Treatment and Matched Control Groups during Pre-treatment Period (2013)

Graphs by catrate
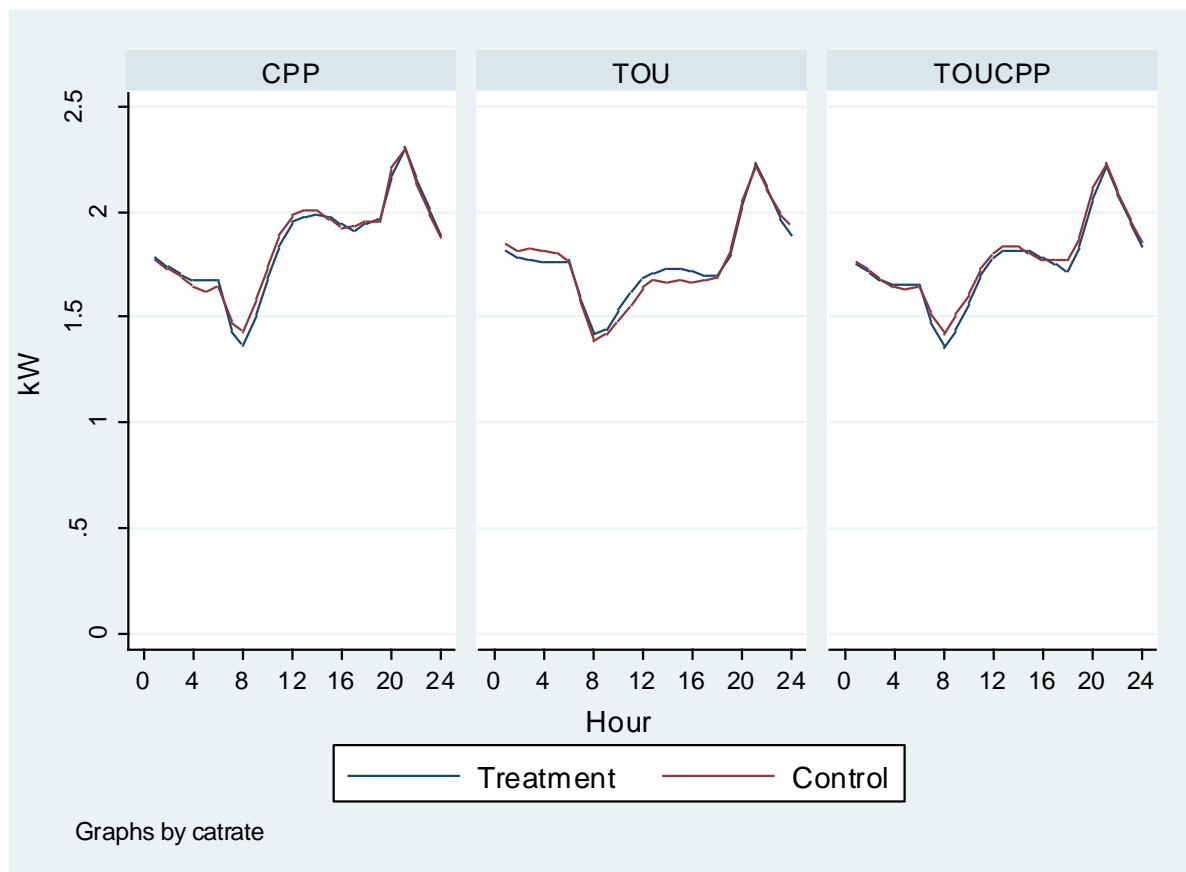
3.3 Difference-in-differences Regression Models

Once a suitable matched control group is found, Nexant estimated program impacts using a difference-in-differences regression model. This methodology is based on the assumption that the program impact is equal to the difference in usage between the treatment and control groups in the post treatment period, minus the pretreatment difference between the two groups. Using difference-in-differences means that the matched control group does not need to perfectly match the treatment group in the pre-treatment period. This is because any differences that may be due to unobservable factors that could not be included in the matching model will be netted out by the differencing. That is; while there may be some preexisting difference between the treatment and control group prior to treatment, we can assume that difference remains the same during and after treatment, and any further change between the groups in the post period can be attributed to the impact of treatment.

Figure 3-3 conceptually illustrates difference-in-differences with repeated observations. If the new rate leads to reductions in demand, then a change in demand will be observed for

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participating customers, but not for control group customers that remain on flat pricing. The timing of the change should coincide with the transition of customers onto the rate.

Figure 3-3: Example of Difference-in-differences with Repeated Observations
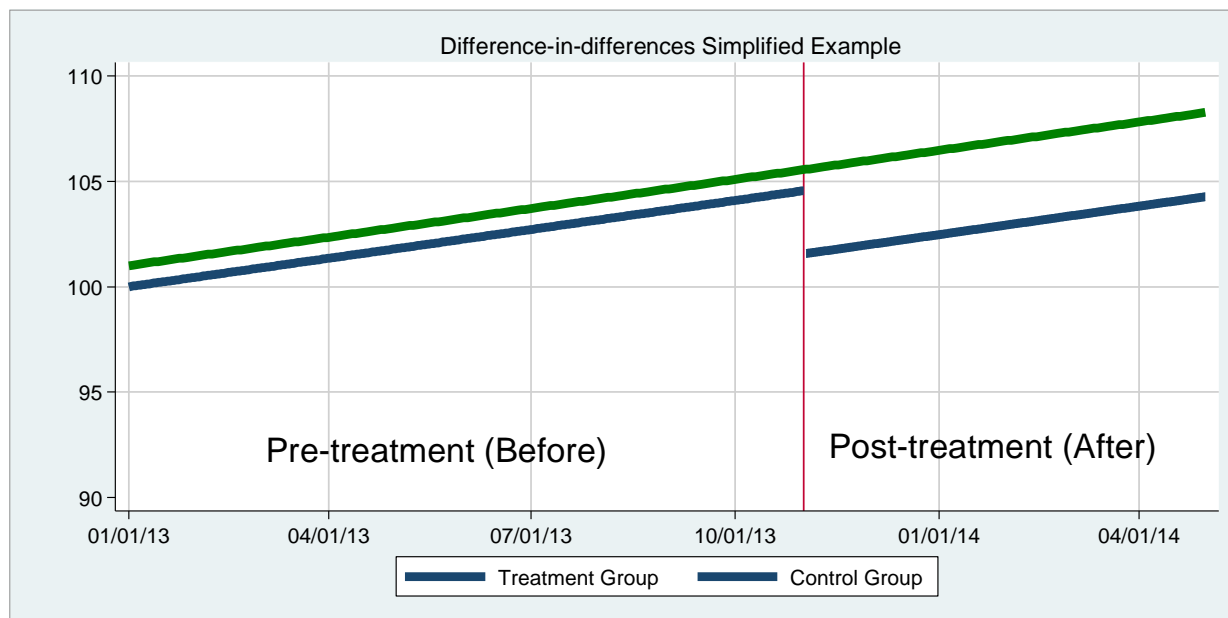
Difference-in-differences estimation can be implemented using either simple means or a panel regression with fixed effects and time effects. For robustness, both methods were used in this evaluation, but the estimates from the regression model are reported due to their increased precision. The increased precision is achieved by including variables that explain energy use, such as temperature and day-of-week effects, which filter background noise (variation) and allow the signal (the response to TOU rates) to be more easily detected.

The difference-in-differences approach relies on having pre-enrollment data to observe both treatment and control groups. For the TOU rate, this is straightforward because all non-holiday weekdays are subject to the TOU rate and we observe the electricity usage of all customers for a period of time before the rate was made available. For the TOU-CPP rate, the idea of pre-treatment data is slightly different. In this case, the rate is in effect only on particularly hot days with high system loads and so it is important that the pre-treatment period be comprised of similarly hot days.

Separate regression equations were estimated for each hour to produce load impact estimates for all hours of the day. The dependent variable in the regression equation is hourly electricity use and only non-holiday weekdays were included in the analysis. The full panel model specification is presented as Equation 1:

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Equation 1: Ex Post Panel Regression Model Specification

$$avgkwh_{i,t} = \beta_0 + \beta_1(posttreatment_t * treatment_i) + \beta_2 posttreatment_t + \beta_3 cdd_{i,t} + \beta_4 hdd_{i,t} + \beta_5 dow_t + \varepsilon_{i,t} + u_i$$

Variable	Definition
i, t	Indicate observations for each individual (i) and date (t).
β_0	The model constant.
β_1	The change in electricity use due to the treatment. This change is only experienced by the treatment group after TOU is implemented. The parameter represents the difference-in-differences.
β_2	The difference pre and post TOU implementation period unrelated to treatment.
β_3	Change in electricity use due to cooling requirements
β_4	Change in electricity use due to heating requirements (heating degree days, base 60).
β_4	Change in electricity use due to day of week
u_i	Customer fixed effects, which control for unobserved factors that are time invariant and unique to each customer. They do not control for fixed characteristics such as air conditioning that interact with time varying factors like weather.
$\varepsilon_{i,t}$	The idiosyncratic (white-noise) error for each individual customer and time period.
$treatment_i$	A binary indicator of whether or not the customer is part of the treatment or control group.
$posttreatment_t$	A binary indicator of whether the time period occurs before (0) or after (1) implementation of TOU.
$cdd_{i,t}$	Total cooling degree hours by date t, base 60
$hdd_{i,t}$	Total heating degree hours by date t, base 60
dow_t	Set of dummy variables for each day of week

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4 TOU Ex Post Load Impact Estimates

Estimates were produced in two main ways for customers enrolled in a TOU rate. Using the matched control groups for this rate, difference-in-differences estimation was performed for high level rate blocks, as well as average hourly load impacts for average and peak weekdays by month. At a high level, impacts across all periods and categories were small and generally lacking in significance. While there were a few instances of significant results, a fundamental property of significance is that with a large enough set of significance tests, some results will be significant just by chance and not due to any underlying relationship. For this reason, these results should be interpreted with caution and even specific instances of significant results should not give indication that particular groups, times of day, or rates are delivering impacts.

Rate blocks were split according to summer and winter seasons, weekday or weekend day type, and the time-varying rate category: On peak, semi-peak (or shoulder peak time), and off peak. Table 4-1 gives the schedule of rate categories for each season. Note that holidays follow a weekend schedule, regardless of season.

Table 4-1: SDG&E Rate Periods for TOU and TOU-CPP Rates

Season	Day Type	Rate Block	Time
	Weekend	Off Peak	All Day
		Off Peak	10pm-6am
		Semi Peak	6am-5pm 8pm-10pm
Winter	Weekday	On Peak	5pm-8pm
	Weekend	Off Peak	All Day
		Off Peak	10pm-6am
		Semi Peak	6am-11am 6pm-10pm
Summer	Weekday	On Peak	11am-6pm

4.1 Results by Rateblock

High level results by rateblock are given in table 4-2 for customers on a TOU rate. With the exception of summer on-peak weekdays, impacts are actually negative, indicating that the treatment customers used more energy during those periods than the control. While, percent impacts are moderate overall, ranging from -3.8% to 3.6%, this is primarily due to the low magnitude of the reference loads. Finally, the standard error of these impacts are approximately the same as the kW impacts, indicating that none of these results are statistically significant. These results should not be interpreted with a high degree of confidence.

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Table 4-2: TOU Average Account Impacts by Rate Block

Season	Day Type	Rate Block	Reference Load (kW)	Impact (kW)	Standard Error of Impact	% Reduction	Aggregate Impact (kW)
	Weekend	Off Peak	1.41	-0.05	0.04	-3.8%	-61.7
		Off Peak	1.55	-0.04	0.04	-2.3%	-40.1
		Semi Peak	1.34	-0.04	0.04	-3.2%	-48.6
Winter	Weekday	On Peak	1.64	-0.06	0.05	-3.8%	-70.5
	Weekend	Off Peak	1.50	-0.04	0.06	-2.8%	-47.5
		Off Peak	1.63	-0.01	0.06	-0.5%	-8.5
		Semi Peak	1.54	-0.01	0.06	-0.9%	-15.0
Summer	Weekday	On Peak	1.56	0.06	0.07	3.6%	63.7

4.2 Results by Monthly Peak Days

Monthly peak days were selected based on SDG&E system loads for non-holiday weekdays in each month. Average on-peak period customer impacts in table 4-3 range from -0.06kW off of a reference load of 1.82kW in January to 0.3kW off of a reference load of 2.10kW. Impacts have a slight seasonality trend, with higher percent impacts in the late summer months, with lower impacts in the spring and early summer. However, none of these results were significant at the 95% or even 90% confidence level.

Table 4-3: TOU Average Account Peak Period Impacts by Monthly Peak Day

Month	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval 10%	Confidence Interval 90%	% Reduction	Avg. Temperature	Aggregate Impact (kW)
January	1.82	-0.06	-2.28	2.16	-3.5%	49.09	-72.54
February	1.96	0.07	-2.15	2.29	3.4%	68.78	76.75
March	1.66	0.01	-2.21	2.23	0.4%	74.78	7.75
April	1.75	0.11	-2.11	2.33	6.2%	73.33	123.11
May	1.48	-0.03	-3.42	3.36	-2.1%	78.99	-35.59
June	1.67	0.10	-3.29	3.49	6.0%	77.70	113.35
July	1.57	-0.04	-3.43	3.35	-2.8%	78.13	-50.58
August	1.94	0.20	-3.20	3.59	10.1%	89.27	223.16
September	2.10	0.30	-3.09	3.69	14.5%	91.19	346.95
October	1.90	0.17	-3.22	3.56	9.1%	83.19	198.10

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Similar to the monthly peak day, on peak impacts for the average weekday by month are shown below in table 4-4. Results in this case were also not significant, with five out of the ten months reporting increases in use for the treatment group relative to the control customers. Both reference loads and impacts are lower for the average weekday as compared to the peak day.

Table 4-4: TOU Average Account Peak Period Impacts by Average Monthly Weekday

Month	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval 10%	Confidence Interval 90%	% Reduction	Avg. Temperature	Aggregate Impact (kW)
January	1.73	-0.14	-2.36	2.08	-7.9%	58.94	-155.27
February	1.77	-0.04	-2.26	2.18	-2.4%	60.73	-48.18
March	1.59	-0.05	-2.27	2.17	-2.9%	65.95	-51.84
April	1.52	0.01	-2.21	2.23	0.8%	65.73	14.60
May	1.20	-0.07	-3.46	3.32	-6.0%	65.96	-81.88
June	1.42	-0.03	-3.42	3.36	-2.2%	73.01	-36.05
July	1.57	0.03	-3.36	3.42	2.0%	75.83	36.41
August	1.75	0.14	-3.25	3.53	7.9%	79.63	156.90
September	1.76	0.16	-3.23	3.55	8.9%	80.38	178.82
October	1.70	0.12	-3.27	3.51	6.8%	79.91	132.96

Hourly results for the August and January monthly peak day and average weekday are shown in figures 4-1 through 4-4.

Figure 4-1: TOU August Monthly Peak Day Hourly Impacts

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	TOU
Day Type	Peak Day
Month	August

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,141
Avg. Load Reduction for Event Window (kW)	2.4
% Load Reduction for Event Window	5.5%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.8	1.7	0.0	2.0%	73.5	0.3	0.1	0.0	-0.1	-0.2
2	1.8	1.7	0.1	3.9%	72.8	0.3	0.2	0.1	0.0	-0.1
3	1.7	1.7	0.0	-0.3%	72.1	0.2	0.1	0.0	-0.1	-0.2
4	1.7	1.7	0.0	1.0%	72.0	0.2	0.1	0.0	-0.1	-0.2
5	1.7	1.7	0.0	2.4%	71.6	0.2	0.1	0.0	0.0	-0.2
6	1.8	1.7	0.1	5.2%	71.2	0.3	0.2	0.1	0.0	-0.1
7	1.6	1.5	0.1	4.9%	71.8	0.3	0.2	0.1	0.0	-0.1
8	1.4	1.3	0.1	8.5%	76.5	0.3	0.2	0.1	0.0	-0.1
9	1.6	1.4	0.2	11.2%	81.8	0.4	0.3	0.2	0.1	0.0
10	1.8	1.5	0.3	14.4%	86.5	0.5	0.3	0.3	0.2	0.0
11	2.0	1.7	0.3	14.5%	89.9	0.5	0.4	0.3	0.2	0.1
12	2.0	1.8	0.2	10.9%	90.9	0.4	0.3	0.2	0.1	0.0
13	2.0	1.8	0.2	11.0%	89.4	0.5	0.3	0.2	0.1	0.0
14	2.0	1.8	0.2	11.9%	89.2	0.5	0.3	0.2	0.1	0.0
15	2.0	1.8	0.2	11.4%	89.3	0.5	0.3	0.2	0.1	0.0
16	1.9	1.7	0.2	8.8%	90.4	0.4	0.3	0.2	0.1	-0.1
17	1.9	1.7	0.2	10.8%	88.8	0.4	0.3	0.2	0.1	0.0
18	1.8	1.7	0.1	5.5%	86.9	0.3	0.2	0.1	0.0	-0.1
19	1.7	1.7	0.0	-2.1%	84.4	0.2	0.1	0.0	-0.1	-0.3
20	1.9	2.0	-0.1	-5.4%	79.9	0.1	0.0	-0.1	-0.2	-0.3
21	2.2	2.2	0.0	0.5%	77.5	0.2	0.1	0.0	-0.1	-0.2
22	2.1	2.1	0.0	0.9%	75.7	0.2	0.1	0.0	-0.1	-0.2
23	2.0	2.0	0.0	1.1%	74.9	0.2	0.1	0.0	-0.1	-0.2
24	1.8	1.8	0.0	-0.2%	73.7	0.2	0.1	0.0	-0.1	-0.2

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	44.0	41.6	2.4	5.5%	80.4	0.7	1.7	2.4	3.2	4.2

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Figure 4-2: TOU August Average Weekday Hourly Impacts

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	TOU
Day Type	Average Weekday
Month	August

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,141
Avg. Load Reduction for Event Window (kW)	1.8
% Load Reduction for Event Window	**4.5%**

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.8	1.7	0.1	4.1%	69.2	0.2	0.1	0.1	0.0	-0.1
2	1.7	1.6	0.1	5.1%	69.0	0.2	0.1	0.1	0.0	0.0
3	1.7	1.6	0.1	3.6%	68.7	0.2	0.1	0.1	0.0	-0.1
4	1.7	1.6	0.1	4.0%	68.5	0.2	0.1	0.1	0.0	-0.1
5	1.7	1.6	0.1	3.3%	68.4	0.2	0.1	0.1	0.0	-0.1
6	1.7	1.6	0.1	4.3%	68.2	0.2	0.1	0.1	0.0	-0.1
7	1.5	1.5	0.0	2.2%	68.9	0.2	0.1	0.0	0.0	-0.1
8	1.3	1.3	0.1	4.2%	70.9	0.2	0.1	0.1	0.0	-0.1
9	1.4	1.3	0.1	6.1%	73.3	0.2	0.1	0.1	0.0	0.0
10	1.5	1.4	0.1	8.2%	76.1	0.3	0.2	0.1	0.1	0.0
11	1.7	1.5	0.1	7.8%	78.4	0.3	0.2	0.1	0.1	0.0
12	1.7	1.6	0.1	7.7%	79.9	0.3	0.2	0.1	0.1	0.0
13	1.8	1.6	0.1	8.3%	80.6	0.3	0.2	0.1	0.1	0.0
14	1.8	1.6	0.1	7.7%	80.5	0.3	0.2	0.1	0.1	0.0
15	1.8	1.6	0.1	7.5%	80.5	0.3	0.2	0.1	0.1	0.0
16	1.8	1.6	0.2	9.8%	79.9	0.3	0.2	0.2	0.1	0.0
17	1.7	1.6	0.2	9.0%	78.9	0.3	0.2	0.2	0.1	0.0
18	1.7	1.6	0.1	5.1%	77.3	0.2	0.1	0.1	0.0	-0.1
19	1.6	1.6	0.0	-0.7%	75.1	0.1	0.0	0.0	-0.1	-0.2
20	1.8	1.9	0.0	-1.8%	72.7	0.1	0.0	0.0	-0.1	-0.2
21	2.1	2.1	0.0	0.9%	71.6	0.2	0.1	0.0	0.0	-0.1
22	2.0	2.0	0.0	1.2%	70.8	0.2	0.1	0.0	0.0	-0.1
23	1.9	1.8	0.0	1.2%	70.2	0.2	0.1	0.0	0.0	-0.1
24	1.8	1.8	0.0	0.8%	69.8	0.1	0.1	0.0	0.0	-0.1
	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	41.0	39.2	1.8	4.5%	73.6	0.1	1.1	1.8	2.6	3.6

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Figure 4-3: TOU January Monthly Peak Day Hourly Impacts

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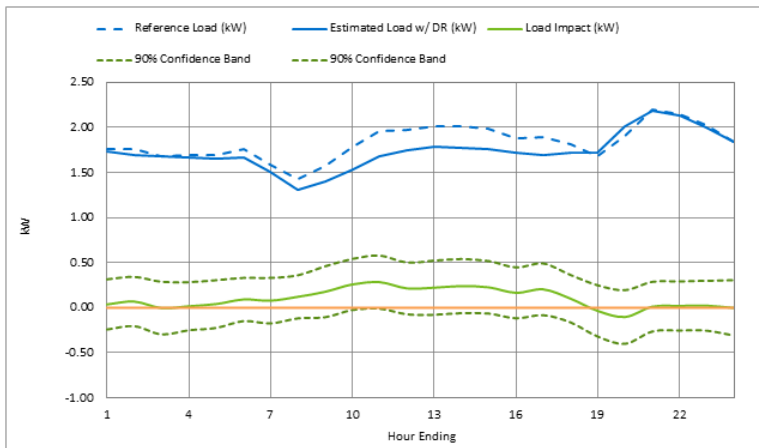**TABLE 2: Event Day Information**

Type of Results	Average Customer
Customer category	All Customers
Rate	TOU
Day Type	Peak Day
Month	January

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,141
Avg. Load Reduction for Event Window (kW)	-0.3
% Load Reduction for Event Window	-0.8%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.5	1.6	-0.1	-5.2%	40.7	0.2	0.0	-0.1	-0.2	-0.4
2	1.5	1.6	-0.1	-3.9%	40.7	0.2	0.1	-0.1	-0.2	-0.4
3	1.5	1.6	0.0	-2.4%	39.6	0.3	0.1	0.0	-0.2	-0.3
4	1.5	1.6	0.0	-2.4%	37.8	0.3	0.1	0.0	-0.2	-0.3
5	1.6	1.6	0.0	0.5%	37.2	0.3	0.1	0.0	-0.1	-0.3
6	1.7	1.6	0.0	1.8%	37.2	0.3	0.1	0.0	-0.1	-0.2
7	1.7	1.6	0.0	2.9%	36.9	0.3	0.2	0.0	-0.1	-0.2
8	1.3	1.3	0.1	5.2%	40.7	0.3	0.2	0.1	0.0	-0.2
9	1.3	1.2	0.1	9.0%	46.6	0.4	0.2	0.1	0.0	-0.1
10	1.3	1.2	0.1	6.8%	51.8	0.3	0.2	0.1	0.0	-0.1
11	1.4	1.3	0.1	6.4%	55.1	0.3	0.2	0.1	0.0	-0.1
12	1.3	1.3	0.0	0.3%	57.9	0.2	0.1	0.0	-0.1	-0.2
13	1.2	1.2	0.0	-2.4%	57.8	0.1	0.0	0.0	-0.1	-0.2
14	1.2	1.2	-0.1	-5.6%	57.6	0.1	0.0	-0.1	-0.1	-0.2
15	1.2	1.2	-0.1	-4.5%	57.1	0.1	0.0	-0.1	-0.1	-0.2
16	1.2	1.2	0.0	-1.1%	56.5	0.1	0.0	0.0	-0.1	-0.2
17	1.3	1.3	-0.1	-5.0%	53.8	0.1	0.0	-0.1	-0.1	-0.2
18	1.8	1.8	0.0	-1.4%	51.3	0.2	0.1	0.0	-0.1	-0.2
19	1.8	1.9	-0.1	-4.8%	48.8	0.1	0.0	-0.1	-0.2	-0.3
20	1.8	1.9	-0.1	-4.2%	47.2	0.2	0.0	-0.1	-0.2	-0.3
21	1.9	1.9	0.0	-2.6%	46.9	0.2	0.1	0.0	-0.2	-0.3
22	1.8	1.8	0.0	-2.3%	45.4	0.2	0.1	0.0	-0.2	-0.3
23	1.7	1.8	0.0	-2.9%	45.4	0.2	0.0	0.0	-0.1	-0.3
24	1.7	1.7	0.0	1.0%	44.2	0.2	0.1	0.0	-0.1	-0.2

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	36.2	36.5	-0.3	-0.8%	47.3	-1.9	-0.9	-0.3	0.4	1.3

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Figure 4-4: TOU January Average Weekday Hourly Impacts

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	TOU
Day Type	Average Weekday
Month	January

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,141
Avg. Load Reduction for Event Window (kW)	-2.6
% Load Reduction for Event Window	**-7.8%**

Legend: Reference Load (kW), Estimated Load w/ DR (kW), Load Impact (kW), 90% Confidence Band, 90% Confidence Band

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.4	1.6	-0.1	-10.0%	53.8	0.0	-0.1	-0.1	-0.2	-0.3
2	1.4	1.6	-0.1	-10.2%	53.4	0.0	-0.1	-0.1	-0.2	-0.3
3	1.4	1.5	-0.1	-10.6%	52.9	0.0	-0.1	-0.1	-0.2	-0.3
4	1.4	1.5	-0.1	-8.9%	52.2	0.0	-0.1	-0.1	-0.2	-0.2
5	1.4	1.5	-0.1	-6.7%	51.9	0.0	-0.1	-0.1	-0.1	-0.2
6	1.5	1.6	-0.1	-6.2%	51.8	0.0	-0.1	-0.1	-0.1	-0.2
7	1.5	1.6	-0.1	-8.9%	51.8	0.0	-0.1	-0.1	-0.2	-0.2
8	1.1	1.3	-0.1	-10.9%	54.4	0.0	-0.1	-0.1	-0.2	-0.2
9	1.1	1.2	0.0	-4.4%	59.3	0.0	0.0	0.0	-0.1	-0.1
10	1.2	1.2	0.0	-2.8%	63.7	0.0	0.0	0.0	-0.1	-0.1
11	1.2	1.2	0.0	-4.2%	67.1	0.0	0.0	0.0	-0.1	-0.1
12	1.2	1.3	-0.1	-6.1%	68.6	0.0	0.0	-0.1	-0.1	-0.1
13	1.2	1.2	-0.1	-7.8%	68.6	0.0	-0.1	-0.1	-0.1	-0.2
14	1.2	1.3	-0.1	-7.2%	67.9	0.0	-0.1	-0.1	-0.1	-0.1
15	1.2	1.2	-0.1	-6.1%	67.1	0.0	0.0	-0.1	-0.1	-0.1
16	1.2	1.2	0.0	-3.5%	65.8	0.0	0.0	0.0	-0.1	-0.1
17	1.2	1.3	-0.1	-4.5%	63.3	0.0	0.0	-0.1	-0.1	-0.1
18	1.7	1.8	-0.1	-6.2%	60.7	0.0	-0.1	-0.1	-0.1	-0.2
19	1.8	1.9	-0.1	-8.4%	58.9	0.0	-0.1	-0.1	-0.2	-0.2
20	1.7	1.9	-0.2	-9.0%	57.3	-0.1	-0.1	-0.2	-0.2	-0.3
21	1.7	1.9	-0.2	-9.2%	56.2	-0.1	-0.1	-0.2	-0.2	-0.3
22	1.6	1.8	-0.2	-10.0%	55.0	-0.1	-0.1	-0.2	-0.2	-0.3
23	1.5	1.7	-0.2	-10.6%	54.4	-0.1	-0.1	-0.2	-0.2	-0.3
24	1.5	1.6	-0.2	-10.7%	53.6	0.0	-0.1	-0.2	-0.2	-0.3

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	33.3	35.9	-2.6	-7.8%	58.7	-4.2	-3.3	-2.6	-1.9	-1.0

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4.3   Results by Pseudo Characteristics

Separate regressions were run for specific segments of the TOU customers and their control groups. Shown below are results for a selected number of categories to illustrate the variation in impacts within the treatment group.

As discussed in previous sections, the customers who voluntarily enrolled in these time-varying rates are not representative of the overall SMB population. Specifically, these customers have significantly more accounts associated with an individual customer number. Shown below in table 4-5 are the TOU impacts for customers, split out by customer size, or how many premises are associated with an individual customer account. Impacts were not significant, and range from -9.5% (an increase compared to the control group) to 14.2%. The relatively large percent impacts are due to the small reference loads forming a small base for the small impacts. While there is some indication that customers with larger numbers of premises deliver higher impacts, caution should be used in interpreting numbers that fail to meet significance thresholds.

Table 4-5: TOU August On Peak Average Load Impacts by Customer Size

# Accounts per Customer	# Premises	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval 10%	Confidence Interval 90%	% Reduction	Avg. Temperature	Aggregate Impact (kW)
1 Account per Customer	195	3.22	0.41	-2.98	3.80	12.7%	89.84	79.69
2-5 Accounts per Customer	136	2.79	-0.52	-3.91	2.87	-18.8%	89.69	-71.08
5-20 Accounts per Customer	153	1.93	0.21	-3.18	3.60	10.7%	90.61	31.63
20+ Accounts per Customer	657	1.38	0.27	-3.12	3.66	19.9%	88.70	179.94

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When splitting customers out by size deciles of average annual consumption, no significant results were found. Table 4-6 shows the results of this exercise. While small customers failed to deliver any reductions at all, larger customers seemed to reduce loads slightly.

Table 4-6: TOU August On Peak Average Load Impacts by Customer Usage

Customer Usage Decile	# Premises	Reference	Average Customer Impact (kW)	Confidence Interval		% Reduction	Avg. Temperature	Aggregate Impact (kW)
		Load (kW)		10%	90%			
1st Decile	403	0.02	-0.06	-3.46	3.33	-392.0%	88.17	6.67
2nd Decile	46	0.20	-0.45	-3.84	2.94	-230.9%	88.02	9.00
3rd Decile	64	0.44	-0.01	-3.40	3.38	-2.4%	88.58	28.05
4th Decile	67	0.71	0.15	-3.24	3.54	20.7%	89.70	47.29
5th Decile	97	0.76	0.03	-3.37	3.42	3.4%	89.86	73.85
6th Decile	92	1.50	0.43	-2.96	3.82	28.8%	90.34	137.87
7th Decile	87	2.66	0.97	-2.42	4.36	36.6%	90.04	231.32
8th Decile	103	2.97	0.29	-3.10	3.68	9.9%	90.89	306.22
9th Decile	72	5.00	0.39	-3.00	3.78	7.8%	90.58	360.20
10th Decile	110	9.15	0.66	-2.73	4.05	7.2%	89.56	1006.00

It is important to note that the lack of statistical significance does not mean that small customers in general do not respond to time-varying price signals. The lack of statistical significance may be due to a combination of small sample sizes, unique load shapes that prove difficult to match, and diverse customers within each industry that increase the amount of noise in the average load shape.

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5 TOU-CPP Ex Post Load Impact Estimates

Due to the nature of the TOU-CPP rate, there are two separate analyses to be considered: one for non-event weekdays and a second for event days. The non-event day analysis is identical to the TOU analysis since TOU and TOU-CPP rates are equivalent on those days. For event days, several modifications to the analysis must be made. The simplest of these is that the post-treatment days of interest for the TOU-CPP rate are each of the four CPP event days called during the summer of 2015 (August 28th, September 9th, 10th and 11th). Because CPP events are typically called on days that are particularly hot, it is also important to identify "event-like" days in the pre-treatment period and remove all other days in the pre-treatment period from the analysis dataset. These proxy days were chosen from the pre-treatment period weekdays that had both high system load and high average temperature.

Results for the TOU-CPP customers on CPP days was significant for the event hours on average, however individual days failed to meet significance criteria. For the non-event days, results were quite similar to those of the TOU customer population, with few significant results which were likely due to random chance.

5.1 Overall Event Day Impacts

Figure 5-1 shows the hourly impacts for the average CPP event day, while table 5-1 shows average event hour impacts for all 2015 CPP events. Events were called on August 28th, September 9th, 10th and 11th from 11am to 6pm. During this time, treatment customers reduced their use by 7.3% or 0.2MW across the 1,468 accounts that were enrolled on the CPP rate during those events.

Table 5-1: CPP Event Day Impacts

Event Day	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval		% Reduction	Avg. Temperature	Aggregate Impact (MW)
			10%	90%			
8/28/2015	2.18	0.14	-0.02	0.31	6.62%	90.5	0.21
9/9/2015	2.26	0.16	-0.01	0.34	7.17%	93.0	0.24
9/10/2015	2.25	0.19	0.02	0.36	8.55%	91.6	0.28
9/11/2015	2.16	0.15	-0.01	0.30	6.75%	86.6	0.21
Average Event Day	2.21	0.16	0.01	0.31	7.28%	90.4	0.24

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Figure 5-1: Average CPP Event Day Hourly Impacts

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TABLE 2: Event Day Information

Type of Results	Aggregate
Customer category	All Customers
Rate	TOU-CPP
Event Day	Avg. Event

TABLE 2: Event Day Information

Event Start	11:00 AM
Event End	6:00 PM
Total Enrolled Accounts	1,468
Avg. Load Reduction for Event Window (MW)	0.2
% Load Reduction for Event Window	**7.3%**

Legend:
- - - Reference Load (MW)
— Estimated Load w/ DR (MW)
— Load Impact (MW)
- - - 90% Confidence Band
- - - 90% Confidence Band

Hour Ending	Reference Load (MW)	Estimated Load w/ DR (MW)	Load Impact (MW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	2.6	2.7	-0.1	-2.6%	77.3	0.1	0.0	-0.1	-0.1	-0.2
2	2.5	2.6	-0.1	-2.5%	76.4	0.1	0.0	-0.1	-0.1	-0.2
3	2.5	2.5	-0.1	-2.1%	76.0	0.1	0.0	-0.1	-0.1	-0.2
4	2.4	2.5	-0.1	-2.8%	76.1	0.1	0.0	-0.1	-0.1	-0.2
5	2.5	2.5	0.0	0.3%	75.8	0.1	0.1	0.0	0.0	-0.1
6	2.5	2.6	0.0	-0.9%	75.6	0.1	0.0	0.0	-0.1	-0.2
7	2.3	2.4	-0.1	-3.9%	76.2	0.1	0.0	-0.1	-0.2	-0.3
8	2.2	2.2	0.0	1.0%	80.1	0.2	0.1	0.0	-0.1	-0.2
9	2.4	2.4	0.1	3.1%	83.6	0.3	0.2	0.1	0.0	-0.1
10	2.7	2.7	0.1	2.1%	87.1	0.3	0.1	0.1	0.0	-0.2
11	3.0	2.9	0.1	3.5%	90.8	0.3	0.2	0.1	0.0	-0.1
12	3.2	3.0	0.2	5.7%	92.1	0.4	0.3	0.2	0.1	-0.1
13	3.3	3.1	0.2	5.8%	91.8	0.4	0.3	0.2	0.1	-0.1
14	3.3	3.1	0.2	6.5%	91.7	0.4	0.3	0.2	0.1	0.0
15	3.4	3.0	0.3	9.6%	90.7	0.5	0.4	0.3	0.2	0.1
16	3.3	3.0	0.3	10.2%	89.9	0.5	0.4	0.3	0.3	0.1
17	3.2	2.9	0.2	7.2%	89.4	0.4	0.3	0.2	0.1	0.0
18	3.0	2.9	0.2	5.8%	87.4	0.4	0.3	0.2	0.1	0.0
19	3.1	2.9	0.2	7.5%	86.0	0.4	0.3	0.2	0.2	0.0
20	3.5	3.5	0.0	0.8%	84.3	0.2	0.1	0.0	0.0	-0.2
21	3.4	3.5	-0.1	-1.5%	82.1	0.1	0.0	-0.1	-0.1	-0.2
22	3.2	3.2	0.0	-1.1%	80.2	0.1	0.0	0.0	-0.1	-0.2
23	2.9	3.0	-0.1	-2.1%	79.3	0.1	0.0	-0.1	-0.1	-0.2
24	2.7	2.8	-0.1	-4.1%	78.1	0.0	0.0	-0.1	-0.2	-0.3

	Reference Energy Use (MWh)	Estimated Energy Use w/ DR (MWh)	Total Load Impact (MWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	69.3	67.8	1.6	2.3%	83.3	0.7	1.2	1.6	1.9	2.5

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5.2   Non-Event Day Impacts by Rateblock

Table 5-2 shows the results for customers enrolled on TOU-CPP rates, split out by rateblock. These rateblocks are defined equivalently to those from the TOU section of this report. However, the four CPP event days have been removed from the analysis dataset prior to estimating the non-event day impacts to avoid attributing load reductions from the CPP event to the TOU portion of the rate. Impacts for these customers by rate block ranged from -0.08kW (or -5.2%) to 0.06kW (or 3.3%). Similar to the TOU rate results, only the summer weekday on peak rate block had a positive impact such that the treatment group used less energy than their control counterparts.

Table 5-2: TOU-CPP Impacts by Rate Block

Season	Day Type	Rate Block	Reference Load (kW)	Impact (kW)	Standard Error of Impact	% Reduction	Aggregate Impact (kW)
Winter	Weekend	Off Peak	1.45	-0.05	0.04	-3.4%	-72.8
	Weekday	Off Peak	1.48	-0.08	0.05	-5.2%	-112.0
		Semi Peak	1.50	-0.02	0.05	-1.2%	-25.4
		On Peak	1.81	-0.07	0.05	-3.6%	-95.6
Summer	Weekend	Off Peak	1.58	-0.05	0.05	-3.3%	-76.4
	Weekday	Off Peak	1.59	-0.07	0.06	-4.7%	-108.7
		On Peak	1.66	-0.03	0.06	-1.6%	-38.0
		Semi Peak	1.81	0.06	0.06	3.3%	87.8

5.3   TOU-CPP Impacts by Month

Load impacts for TOU-CPP customers on non-event days are presented in Table 5-2. The results are very similar to those for TOU customers, with impacts generally being small in absolute terms and statistically indistinguishable from zero. Estimated standard errors are substantially larger than the absolute impacts, indicating that the estimates are very noisy and should not be interpreted with a high degree of confidence. No seasonal trend was observed in either the peak day on-peak impacts shown in table 5-3 or in the average weekday on-peak impacts shown in table 5-4.

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Table 5-3: Peak Period Load Impacts for TOU-CPP Customers on Non-event Monthly Peak Days

Month	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval		% Reduction	Avg. Temperature	Aggregate Impact (kW)
			10%	90%			
January	1.82	-0.09	-2.31	2.13	-4.9%	49.81	-130.87
February	2.31	0.24	-1.98	2.46	10.5%	69.68	355.09
March	1.87	-0.01	-2.23	2.21	-0.4%	75.63	-11.95
April	1.92	0.03	-2.19	2.25	1.7%	74.94	47.00
May	1.83	0.07	-3.32	3.46	3.8%	80.81	100.89
June	1.88	0.06	-3.33	3.46	3.4%	78.86	95.18
July	1.87	0.01	-3.38	3.40	0.5%	78.51	15.04
August	2.04	0.02	-3.37	3.41	1.0%	88.66	30.71
September	2.11	0.08	-3.31	3.47	3.8%	89.83	119.01
October	2.09	0.12	-3.27	3.51	5.8%	84.04	177.75

Load impacts for peak periods on the average weekday by month are shown below for TOU-CPP customers. Impacts are very small; ranging from -0.16kW per customer to 0.13kW. Again, small reference loads can create the impression of larger percent impacts, but absolute values indicate that these impacts are very small and should not be interpreted as statistically significant. Based on these results, combined with those in Table 5-3, there is no evidence of any load reductions that can be attributed to the SPP rates. Given the strategic targeting of structural winners and the unique subset of customers who chose to enroll, these results should not be interpreted as what might happen if these rates were offered to the broader population as either opt-in or default tariffs.

Table 5-4: Peak Period Load Impacts for TOU-CPP Customers on Non-event Average Weekdays

Month	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval		% Reduction	Avg. Temperature	Aggregate Impact (kW)
			10%	90%			
January	1.82	-0.16	-2.38	2.06	-8.8%	59.60	-235.29
February	1.96	-0.02	-2.24	2.20	-0.9%	61.27	-27.05
March	1.81	-0.02	-2.24	2.20	-1.2%	66.50	-31.51
April	1.68	-0.03	-2.25	2.19	-2.1%	66.02	-50.71
May	1.53	0.03	-3.36	3.42	2.1%	66.09	46.10
June	1.76	0.05	-3.34	3.45	3.1%	73.78	80.34
July	1.81	0.02	-3.37	3.41	1.3%	76.36	34.13
August	2.00	0.13	-3.26	3.52	6.4%	79.95	187.15
September	1.88	0.04	-3.36	3.43	1.9%	79.37	52.00
October	1.90	0.11	-3.28	3.50	5.7%	80.46	159.74

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Hourly results for both peak and average days by month are shown in figures 5-2 through 5-5. As a sample of the monthly data available in the electronically attached load impact tables, they show a sample of impacts for both summer and winter months.

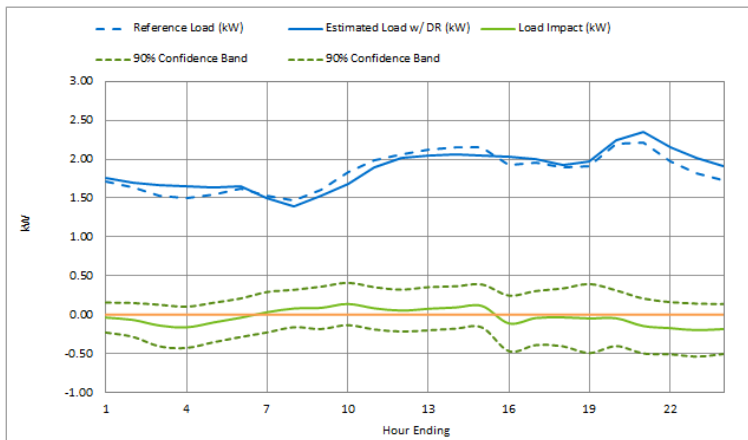**Figure 5-2: TOU CPP August Monthly Peak Day Aggregate Impacts**

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	CPP-TOU
Day Type	Peak Day
Month	August

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,468
Avg. Load Reduction for Event Window (kW)	-0.8
% Load Reduction for Event Window	-1.8%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.7	1.8	0.0	-2.1%	72.4	0.1	0.0	0.0	-0.1	-0.2
2	1.6	1.7	-0.1	-4.1%	72.1	0.1	0.0	-0.1	-0.1	-0.2
3	1.5	1.7	-0.1	-9.1%	72.0	0.1	-0.1	-0.1	-0.2	-0.3
4	1.5	1.7	-0.2	-10.8%	71.5	0.0	-0.1	-0.2	-0.2	-0.4
5	1.5	1.6	-0.1	-6.5%	71.7	0.1	0.0	-0.1	-0.2	-0.3
6	1.6	1.7	0.0	-2.5%	71.1	0.2	0.0	0.0	-0.1	-0.2
7	1.5	1.5	0.0	2.1%	71.3	0.2	0.1	0.0	-0.1	-0.2
8	1.5	1.4	0.1	5.4%	74.7	0.3	0.2	0.1	0.0	-0.1
9	1.6	1.5	0.1	5.4%	78.9	0.3	0.2	0.1	0.0	-0.1
10	1.8	1.7	0.1	7.6%	84.0	0.4	0.2	0.1	0.1	-0.1
11	2.0	1.9	0.1	4.1%	85.8	0.3	0.2	0.1	0.0	-0.1
12	2.1	2.0	0.1	2.6%	87.6	0.3	0.1	0.1	0.0	-0.2
13	2.1	2.1	0.1	3.6%	88.7	0.3	0.2	0.1	0.0	-0.1
14	2.1	2.1	0.1	4.3%	88.7	0.3	0.2	0.1	0.0	-0.1
15	2.2	2.0	0.1	5.2%	91.1	0.3	0.2	0.1	0.0	-0.1
16	1.9	2.0	-0.1	-5.8%	89.8	0.2	0.0	-0.1	-0.2	-0.4
17	2.0	2.0	0.0	-2.2%	88.6	0.2	0.1	0.0	-0.2	-0.3
18	1.9	1.9	0.0	-1.8%	86.0	0.3	0.1	0.0	-0.2	-0.3
19	1.9	2.0	0.0	-2.5%	81.6	0.3	0.1	0.0	-0.2	-0.4
20	2.2	2.2	0.0	-2.1%	78.2	0.2	0.1	0.0	-0.2	-0.3
21	2.2	2.4	-0.1	-6.6%	76.9	0.1	0.0	-0.1	-0.3	-0.4
22	2.0	2.1	-0.2	-8.8%	75.7	0.1	-0.1	-0.2	-0.3	-0.4
23	1.8	2.0	-0.2	-10.9%	75.7	0.1	-0.1	-0.2	-0.3	-0.5
24	1.7	1.9	-0.2	-10.7%	75.0	0.1	-0.1	-0.2	-0.3	-0.4

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	44.1	44.8	-0.8	-1.8%	79.5	-2.6	-1.5	-0.8	0.0	1.0

31

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Figure 5-3: TOU CPP August Average Weekday Aggregate Impacts

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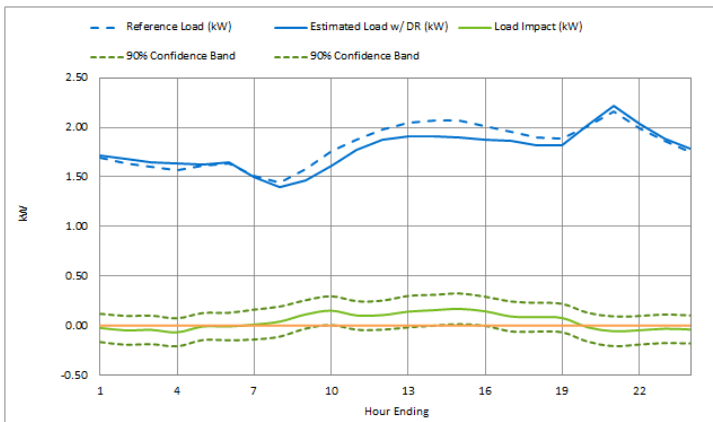2015 Ex Post Load Impacts - SMB TOU & TOU CPP   Nexant

TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	CPP-TOU
Day Type	Average Weekday
Month	August

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,468
Avg. Load Reduction for Event Window (kW)	1.0
% Load Reduction for Event Window	2.3%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.7	1.7	0.0	-1.4%	69.2	0.1	0.0	0.0	-0.1	-0.1
2	1.6	1.7	0.0	-2.9%	68.9	0.1	0.0	0.0	-0.1	-0.2
3	1.6	1.7	0.0	-2.7%	68.6	0.1	0.0	0.0	-0.1	-0.2
4	1.6	1.6	-0.1	-4.3%	68.5	0.0	0.0	-0.1	-0.1	-0.2
5	1.6	1.6	0.0	-0.6%	68.3	0.1	0.0	0.0	-0.1	-0.1
6	1.6	1.6	0.0	-0.6%	68.2	0.1	0.0	0.0	-0.1	-0.1
7	1.5	1.5	0.0	0.7%	68.8	0.1	0.1	0.0	0.0	-0.1
8	1.4	1.4	0.0	2.8%	70.5	0.2	0.1	0.0	0.0	-0.1
9	1.6	1.5	0.1	7.1%	72.8	0.2	0.2	0.1	0.1	0.0
10	1.8	1.6	0.2	8.6%	75.7	0.3	0.2	0.2	0.1	0.0
11	1.9	1.8	0.1	5.4%	78.3	0.2	0.1	0.1	0.1	0.0
12	2.0	1.9	0.1	5.3%	80.0	0.2	0.2	0.1	0.1	0.0
13	2.0	1.9	0.1	6.9%	81.0	0.3	0.2	0.1	0.1	0.0
14	2.1	1.9	0.2	7.5%	80.9	0.3	0.2	0.2	0.1	0.0
15	2.1	1.9	0.2	8.2%	80.9	0.3	0.2	0.2	0.1	0.0
16	2.0	1.9	0.1	7.2%	80.2	0.3	0.2	0.1	0.1	0.0
17	2.0	1.9	0.1	4.7%	79.1	0.2	0.1	0.1	0.0	0.0
18	1.9	1.8	0.1	4.5%	77.6	0.2	0.1	0.1	0.0	0.0
19	1.9	1.8	0.1	4.0%	75.1	0.2	0.1	0.1	0.0	0.0
20	2.0	2.0	0.0	-0.9%	72.5	0.1	0.0	0.0	-0.1	-0.1
21	2.2	2.2	-0.1	-2.6%	71.4	0.1	0.0	-0.1	-0.1	-0.2
22	2.0	2.0	0.0	-2.4%	70.7	0.1	0.0	0.0	-0.1	-0.2
23	1.9	1.9	0.0	-1.7%	70.3	0.1	0.0	0.0	-0.1	-0.1
24	1.7	1.8	0.0	-2.3%	69.9	0.1	0.0	0.0	-0.1	-0.1

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	43.6	42.6	1.0	2.3%	73.6	-0.8	0.3	1.0	1.7	2.8

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Figure 5-4: TOU CPP January Monthly Peak Day Aggregate Impacts

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	CPP-TOU
Day Type	Peak Day
Month	January

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,468
Avg. Load Reduction for Event Window (kW)	-2.2
% Load Reduction for Event Window	-6.4%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.4	1.5	-0.1	-5.4%	41.2	0.1	0.0	-0.1	-0.1	-0.3
2	1.5	1.5	0.0	-2.6%	41.0	0.1	0.0	0.0	-0.1	-0.2
3	1.5	1.5	0.0	0.0%	40.0	0.2	0.1	0.0	-0.1	-0.2
4	1.4	1.5	-0.1	-3.9%	38.1	0.1	0.0	-0.1	-0.1	-0.2
5	1.4	1.5	-0.1	-5.3%	37.3	0.1	0.0	-0.1	-0.1	-0.2
6	1.4	1.5	-0.1	-9.2%	37.7	0.1	-0.1	-0.1	-0.2	-0.3
7	1.4	1.5	-0.1	-8.1%	37.6	0.1	0.0	-0.1	-0.2	-0.3
8	1.1	1.3	-0.2	-13.8%	41.1	0.0	-0.1	-0.2	-0.2	-0.3
9	1.2	1.3	-0.1	-9.7%	46.9	0.1	0.0	-0.1	-0.2	-0.3
10	1.2	1.4	-0.2	-15.1%	51.5	0.0	-0.1	-0.2	-0.3	-0.4
11	1.3	1.4	-0.1	-5.0%	55.0	0.1	0.0	-0.1	-0.1	-0.3
12	1.4	1.4	0.0	-0.8%	57.9	0.2	0.1	0.0	-0.1	-0.2
13	1.3	1.4	0.0	-1.2%	58.1	0.2	0.1	0.0	-0.1	-0.2
14	1.3	1.4	-0.1	-8.0%	57.8	0.1	0.0	-0.1	-0.2	-0.3
15	1.2	1.3	-0.1	-11.3%	57.2	0.1	-0.1	-0.1	-0.2	-0.3
16	1.2	1.3	-0.1	-8.6%	56.4	0.1	0.0	-0.1	-0.2	-0.3
17	1.3	1.5	-0.2	-16.0%	53.7	0.0	-0.1	-0.2	-0.3	-0.4
18	1.8	1.9	-0.1	-6.4%	51.8	0.1	0.0	-0.1	-0.2	-0.3
19	1.9	1.9	-0.1	-3.4%	49.5	0.1	0.0	-0.1	-0.1	-0.2
20	1.8	1.9	-0.1	-4.9%	48.1	0.1	0.0	-0.1	-0.2	-0.3
21	1.8	1.8	-0.1	-4.3%	47.7	0.1	0.0	-0.1	-0.2	-0.3
22	1.7	1.8	0.0	-2.7%	46.5	0.1	0.0	0.0	-0.1	-0.2
23	1.6	1.7	-0.1	-5.5%	46.0	0.1	0.0	-0.1	-0.2	-0.3
24	1.5	1.6	-0.2	-10.6%	44.8	0.0	-0.1	-0.2	-0.2	-0.3
	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	34.3	36.5	-2.2	-6.4%	47.6	-3.8	-2.9	-2.2	-1.5	-0.6

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Figure 5-5: TOU CPP January Average Weekday Aggregate Impacts

San Diego Gas & Electric
2015 Ex Post Load Impacts - SMB TOU & TOU CPP

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TABLE 2: Event Day Information

Type of Results	Average Customer
Customer category	All Customers
Rate	CPP-TOU
Day Type	Average Weekday
Month	January

TABLE 2: Typical Day Information

Event Start	All Day
Event End	All Day
Total Enrolled Accounts	1,468
Avg. Load Reduction for Event Window (kW)	-2.2
% Load Reduction for Event Window	-6.2%

Hour Ending	Reference Load (kW)	Estimated Load w/ DR (kW)	Load Impact (kW)	%Load Reduction	Temperature (F)	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	1.4	1.5	-0.1	-6.3%	54.4	0.0	-0.1	-0.1	-0.1	-0.2
2	1.4	1.5	-0.1	-6.8%	54.1	0.0	-0.1	-0.1	-0.1	-0.2
3	1.4	1.5	-0.1	-6.2%	53.6	0.0	-0.1	-0.1	-0.1	-0.2
4	1.4	1.5	-0.1	-5.4%	53.0	0.0	0.0	-0.1	-0.1	-0.1
5	1.4	1.5	-0.1	-5.7%	52.4	0.0	-0.1	-0.1	-0.1	-0.1
6	1.4	1.5	-0.1	-5.0%	52.2	0.0	0.0	-0.1	-0.1	-0.1
7	1.5	1.5	0.0	-2.2%	52.3	0.0	0.0	0.0	-0.1	-0.1
8	1.2	1.3	0.0	-2.9%	54.8	0.0	0.0	0.0	-0.1	-0.1
9	1.3	1.3	0.0	-2.5%	59.8	0.0	0.0	0.0	-0.1	-0.1
10	1.3	1.4	-0.1	-7.2%	64.1	0.0	-0.1	-0.1	-0.1	-0.2
11	1.3	1.4	-0.1	-5.9%	67.3	0.0	0.0	-0.1	-0.1	-0.2
12	1.4	1.5	0.0	-3.5%	69.0	0.1	0.0	0.0	-0.1	-0.1
13	1.4	1.5	-0.1	-4.3%	69.1	0.0	0.0	-0.1	-0.1	-0.2
14	1.4	1.5	-0.1	-5.2%	68.6	0.0	0.0	-0.1	-0.1	-0.2
15	1.4	1.4	-0.1	-5.7%	67.6	0.0	0.0	-0.1	-0.1	-0.2
16	1.3	1.4	-0.1	-5.6%	66.2	0.0	0.0	-0.1	-0.1	-0.2
17	1.4	1.5	-0.1	-9.5%	63.4	0.0	-0.1	-0.1	-0.2	-0.2
18	1.8	2.0	-0.1	-7.9%	61.1	0.0	-0.1	-0.1	-0.2	-0.2
19	1.9	2.0	-0.2	-8.4%	59.6	-0.1	-0.1	-0.2	-0.2	-0.3
20	1.8	2.0	-0.2	-10.2%	58.2	-0.1	-0.1	-0.2	-0.2	-0.3
21	1.7	1.9	-0.2	-10.2%	57.0	-0.1	-0.1	-0.2	-0.2	-0.3
22	1.6	1.7	-0.1	-6.0%	55.9	0.0	-0.1	-0.1	-0.1	-0.2
23	1.6	1.6	-0.1	-6.0%	55.2	0.0	-0.1	-0.1	-0.1	-0.2
24	1.5	1.6	-0.1	-7.6%	54.4	0.0	-0.1	-0.1	-0.1	-0.2

	Reference Energy Use (kWh)	Estimated Energy Use w/ DR (kWh)	Total Load Impact (kWh)	% Daily Load Change	Average Temperature	Uncertainty Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily	35.1	37.3	-2.2	-6.2%	59.3	-3.8	-2.8	-2.2	-1.5	-0.6

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5.4 TOU-CPP Impacts by Category

Results for non-event days for customers enrolled in the TOU-CPP rate are shown in the tables below. Additional customer segments can be found in the attached load impact tables. A sample of customer segments are shown here. Table 5-5 shows customers split out by the number of premises that are linked to one customer. Estimated impacts were again not statistically significant, and small reference loads contributed to the large percent impacts for customers with more than 5 premises per customer. For customers with 5-20 accounts per customer, impacts were large and negative, indicating that treatment group customers in this group increased load compared to their control group.

Table 5-5: On Peak August Peak Day Impacts for TOU-CPP customers by Customer Size

# Accounts per Customer	# Premises	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval 10%	90%	% Reduction	Avg. Temperature	Aggregate Impact (kW)
1 Account per Customer	320	3.87	0.09	-3.31	3.48	2.2%	89.19	27.28
2-5 Accounts per Customer	184	4.17	0.09	-3.30	3.48	2.1%	89.55	16.41
5-20 Accounts per Customer	74	1.28	-0.88	-4.27	2.51	-68.6%	90.82	-64.95
20+ Accounts per Customer	890	1.00	0.06	-3.33	3.45	5.6%	88.10	49.90

Impacts by customer usage deciles are relatively noisy and should not be interpreted as significant. While the smaller 50% of customers had large impacts, these are based off of a weighted average reference load of 0.32kW. The larger 50% of customers had a weighted average reference load of 4.89kW per customer and relatively more stable percent impacts. However the largest decile of customers had a -8.8% impact, or -0.83kW. More details are shown in table 5-6.

**Table 5-6: On Peak August Weekday Impacts for TOU-CPP customers by Customer Size**

Customer Usage Decile	# Premises	Reference Load (kW)	Average Customer Impact (kW)	Confidence Interval 10%	90%	% Reduction	Avg. Temperature	Aggregate Impact (kW)
1st Decile	529	0.12	0.09	-3.30	3.48	72.3%	88.10	45.41
2nd Decile	139	0.31	0.03	-3.36	3.43	11.3%	88.29	4.86
3rd Decile	109	0.70	0.32	-3.07	3.71	45.0%	88.33	34.49
4th Decile	74	0.70	-0.07	-3.46	3.32	-9.5%	89.21	-4.88
5th Decile	89	1.19	-0.01	-3.40	3.38	-1.0%	88.71	-1.09
6th Decile	83	1.31	0.10	-3.29	3.49	7.3%	89.75	7.96
7th Decile	73	2.53	0.45	-2.94	3.85	18.0%	89.95	33.19
8th Decile	102	3.32	0.57	-2.82	3.96	17.1%	89.33	57.87
9th Decile	115	5.01	0.75	-2.64	4.14	14.9%	88.41	85.95
10th Decile	155	9.31	-1.53	-4.92	1.86	-16.4%	89.37	-237.15

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Ex Ante Methodology

6   Ex Ante Methodology

The magnitude of demand reduction that can be acquired is fundamentally the result of customer preferences, pricing structure, magnitude of price signals, and enrollment/targeting policies. There are three fundamental building blocks needed to forecast SPP rate load impacts as shown in Figure 6-1:

- An estimate of energy use in 1-in-2 and 1-in-10 weather conditions before demand response impacts take effect;

- An estimate of the percent reductions resulting from customer participation based on PG&E's 2013 default of small commercial accounts on to TOU rates, as well as the impacts associated with default CPP rates on the same customer segment starting in PG&E's territory prior to the summer of 2015.

- Enrollment projections for future years. SDG&E furnished this forecast for ex ante enrollment by month starting in 2016 and extending through 2026.

Figure 6-1: Key Building Blocks for SPP Rate Ex Ante Load Impact Projections
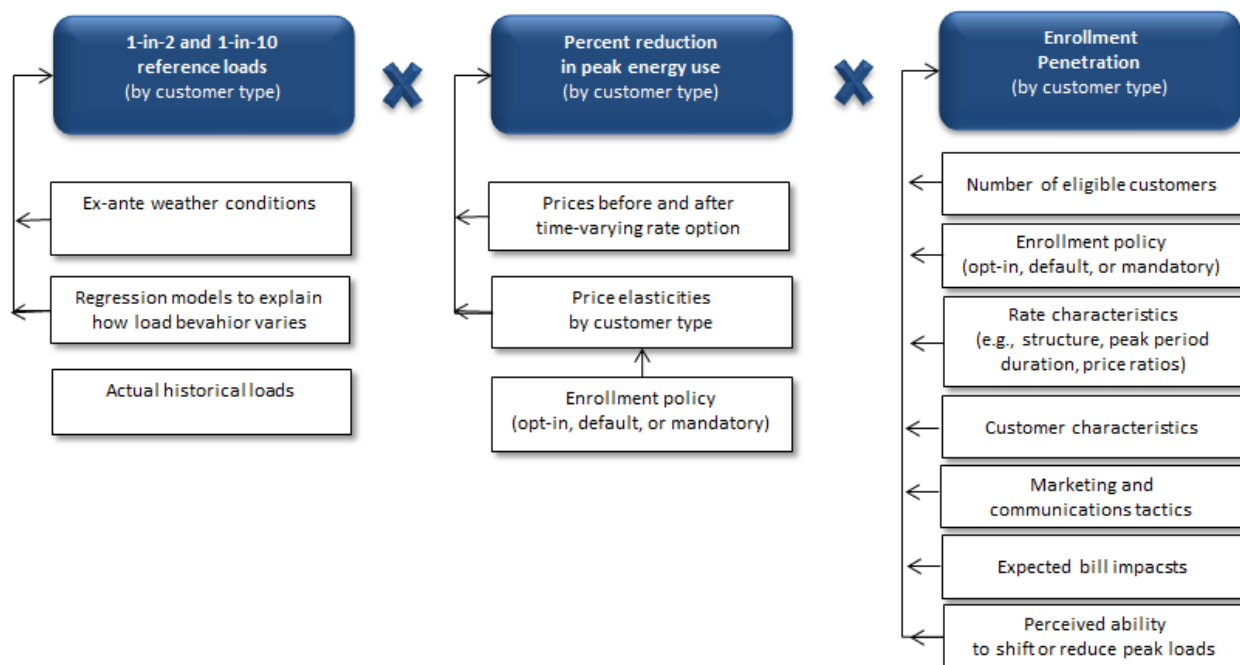
For all SPP rates there are seven main steps in producing ex ante impacts:

1. Analyze how enrollment varies across customer segments and ensure the starting load values reflect those segments. This step is particularly important for opt-in and default options because customers who enroll and remain on time varying rates self-select and likely differ from the average customer.

2. Run regression models based on actual electricity use patterns under flat rates and use those models to estimate reference loads under 1-in-10 and 1-in-2 weather conditions.

3. Apply the impacts evaluated empirically from PG&E default TOU and TOU-CPP evaluations.

4. Calculate per customer load reductions by applying the percent load reductions to customer 1-in-2 and 1-in-10 reference loads.

5. Combine per customer impacts for each of the relevant customer segments with forecasted enrollment levels. It is important to ensure the load reflects the type of customers who enroll and remain on time-varying rates.

This section provides an overview of small commercial ex ante estimates, with a focus on the uncertainties associated with the estimates. Results for both SDG&E and CAISO 1-in-2 and 1-in-10 weather forecasts are provided by industry.

SDG&E's small commercial customers will be defaulted onto the TOU-CPP rate, with the option of selecting the TOU rate instead. The starting point for forecasting the load impacts associated with transitioning all of SDG&E's small commercial customers to SPP rates is the analysis of PG&E's transition to mandatory TOU rates for all of its non-residential customers. PG&E's TOU rate is very similar (both in prices and rate periods) to the SPP TOU rate. Because of this similarity, the high level strategy for obtaining ex ante estimates is to apply the estimated percent impacts from the PG&E evaluation to reference loads for SDG&E small commercial customers under predetermined sets of weather conditions. This section describes the steps associated with implementing this strategy as well as the implicit assumptions underlying it.

6.1 Enrollment Forecast

SDG&E provided an enrollment forecast for monthly enrollment in both TOU and TOU CPP rates starting in January of 2016. Customers began to be defaulted on to the TOU CPP rate starting in November of 2015, with the option of opting out and on to the TOU-only rate. Table 6-1 shows the overall growth of small commercial and agricultural customers over time, combined with a decreasing TOU-CPP yield which leads to a growing number of customers on the TOU-only rate over time.

Table 6-1: Enrollment Estimates by Rate Type for August of Ex Ante Years

Year	TOU-CPP	TOU	All
2016	106,274	9,844	116,118
2017	95,105	21,284	116,389
2018	89,520	26,979	116,499
2019	89,520	27,106	116,627
2020	89,520	27,215	116,735
2021	89,520	27,318	116,839
2022	89,520	27,318	116,839
2023	89,520	27,318	116,839
2024	89,520	27,318	116,839
2025	89,520	27,318	116,839
2026	89,520	27,318	116,839

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6.2   Reference Loads

Reference loads provide a baseline level of consumption for customers representing what their electricity usage would be in the future if they did not switch to an SPP rate, but rather remained on their current rate (i.e., they are an estimate of counterfactual consumption). Reference loads can be compared to the predicted loads for customers after they transition to SPP rates to assess the effect of the new rates.

Since nearly all small commercial customers in SDG&E's service territory are currently on a non-time-varying rate, there is ample data that can be used to model reference loads. The best approach for this modeling (in the absence of holding back a control group) is to develop a regression model that predicts electricity consumption as a function of weather conditions, month, day of week, hour of day, and other variables that influence usage. To develop the best possible model, 10 specifications were tested and the one that most accurately predicted loads during an out-of-sample test on 10% of the customers was selected as the final model. This model is shown as Equation 2:

Equation 2: Ex Ante Reference Load Model Specification

$$kwh_{i,h} = \beta_0 + \beta_1(CDD_d * weekday_d) + \beta_2(CDD_d^2 * weekday_d) + \beta_3 weekday_d + \beta_4 month_d + \varepsilon_{i,h}$$

Variable	Definition
h, i, d	Indicate observations for each hour (h), industry (i) and day (d).
β_0	The model constant.
CDD_d	Cooling degree days on day d, defined as max(0, Avg. daily temp – 60).
$weekday_d$	A binary indicator of whether the day of the observation is a weekday (0=weekend, 1=weekday).
$month_d$	Set of dummy variables for each month of the year.
ε_h	Error term (assumed to be mean zero and independent of all other regressors).

The reference load model was estimated separately for each small commercial industry type for each hour of the day and includes terms for a weekday dummy variable interacted with cooling degree days, the same weekday dummy interacted with cooling degree days squared, the weekday dummy by itself, and a set of dummy variables for the months of the year. This specification captures changes in weather conditions as well as seasonal variation in electricity usage and was used to estimate reference loads for every combination of industry, day type (weekday or weekend), month, and set of weather conditions. Estimated reference loads for the average small commercial customer throughout the year are presented in table 6-1.

The values in the table represent average peak period load during the peak period for monthly peak days under each set of weather conditions. The highest reference loads during the peak period for this group of customers occur in September for each of the weather scenarios, with the exception of the CAISO 1-in-2 scenario, which peaks in August. During the summer months, the CAISO and SDG&E based reference loads (and underlying weather) are quite similar under

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1-in-2 year conditions. For 1-in-10 year conditions, the SDG&E based weather conditions are typically a bit higher than the CAISO based conditions.

Table 6-1: Estimated Peak Period Reference Loads for Small Commercial and Agricultural Customers Under Ex Ante Weather Conditions

Month	Reference Loads (kW)			
	CAISO		SDG&E	
	1-in-2	1-in-10	1-in-2	1-in-10
January	2.05	2.05	2.05	2.05
February	2.03	2.03	2.03	2.03
March	2.00	2.13	2.00	2.09
April	1.97	2.22	2.01	2.29
May	2.48	2.95	2.64	3.08
June	2.84	3.12	2.83	3.13
July	3.07	3.18	3.08	3.42
August	3.47	3.51	3.40	3.66
September	3.46	3.77	3.42	3.74
October	3.09	3.41	3.20	3.53
November	2.10	2.25	2.12	2.32
December	2.05	2.05	2.05	2.05

6.3 Impact Estimates

Estimates from the 2013 PG&E mandatory TOU evaluation for small and medium commercial customers are presented in Table 6-2 by industry. While impact estimates exist for the 2014 evaluation of small and medium commercial TOU rates, the resulting impacts were only reported at the aggregate level and not broken out by industry. Since the industry mix is different between SDG&E and PG&E, these aggregate impacts could not be used because they would reflect only PG&E-territory weighted industry results. There are three features of these results that are particularly interesting and relevant to ex ante impact estimation for SDG&E. The first is that the magnitudes of the impacts for most industries are large given the relatively small price differentials between the peak and off-peak periods. One possible explanation for this outcome is that the PG&E impacts capture a base behavioral response that is associated with changing to TOU rates. Prior studies have not studied this issue in depth and instead have relied on large TOU price differentials and small sample sizes. If it is indeed the case that some amount of the response to TOU rates is "fixed," then observed impacts should not be interpreted purely as price impacts because they also reflect behavioral responses triggered by non-price features of the rate transition. Using the PG&E results as the basis for ex ante forecasts for PG&E assumes that a similar "rate transition" effect will occur for SPP rates.

Table 6-2: Industry Level Results from PG&E Non-res Mandatory TOU Evaluation for Average Customers

Industry Type	Season	Day type	Rate Block	Ref Load (kW)	% Reduction	Impact (kW)	Standard Error
Agriculture, Mining & Construction	Summer	Weekdays	Peak	2.27	8.8%	0.20	0.024
			Part-Peak	1.86	6.2%	0.11	0.026
			Off-Peak	1.25	-1.2%	-0.01	0.025
		Weekends & Holidays	Off-Peak	1.29	3.8%	0.05	0.024
	Non-Summer	Weekdays	Part-Peak	1.71	14.8%	0.25	0.011
			Off-Peak	1.18	11.6%	0.14	0.012
		Weekends & Holidays	Off-Peak	1.07	13.7%	0.15	0.014
Institutional/ Government	Summer	Weekdays	Peak	2.64	7.5%	0.20	0.013
			Part-Peak	2.16	6.7%	0.14	0.007
			Off-Peak	1.16	9.1%	0.11	0.008
		Weekends & Holidays	Off-Peak	1.46	4.0%	0.06	0.010
	Non-Summer	Weekdays	Part-Peak	2.20	8.5%	0.19	0.006
			Off-Peak	1.16	8.5%	0.10	0.009
		Weekends & Holidays	Off-Peak	1.35	5.9%	0.08	0.007
Manufacturing	Summer	Weekdays	Peak	3.93	-6.0%	-0.24	0.046
			Part-Peak	3.02	-4.8%	-0.14	0.030
			Off-Peak	1.66	-1.3%	-0.02	0.012
		Weekends & Holidays	Off-Peak	1.45	5.4%	0.08	0.053
	Non-Summer	Weekdays	Part-Peak	3.24	3.2%	0.10	0.041
			Off-Peak	1.67	3.0%	0.05	0.015
		Weekends & Holidays	Off-Peak	1.43	13.3%	0.19	0.046
Offices, Hotels, Finance, Services	Summer	Weekdays	Peak	3.41	3.2%	0.11	0.007
			Part-Peak	2.59	3.6%	0.09	0.005
			Off-Peak	1.62	2.0%	0.03	0.004
		Weekends & Holidays	Off-Peak	1.82	1.7%	0.03	0.005
	Non-Summer	Weekdays	Part-Peak	2.47	4.9%	0.12	0.008
			Off-Peak	1.61	2.5%	0.04	0.003
		Weekends & Holidays	Off-Peak	1.62	2.6%	0.04	0.004
Other or Unknown	Summer	Weekdays	Peak	2.28	2.5%	0.06	0.006
			Part-Peak	1.78	1.2%	0.02	0.004
			Off-Peak	1.16	-1.5%	-0.02	0.004
		Weekends & Holidays	Off-Peak	1.29	0.6%	0.01	0.006
	Non-Summer	Weekdays	Part-Peak	1.76	2.5%	0.04	0.005
			Off-Peak	1.16	0.8%	0.01	0.006

Industry Type	Season	Day type	Rate Block	Ref Load	%	Impact	Standard
		Weekends & Holidays	Off-Peak	1.16	1.3%	0.02	0.006
Retail Stores	Summer	Weekdays	Peak	4.33	1.1%	0.05	0.014
			Part-Peak	2.98	2.4%	0.07	0.012
			Off-Peak	1.53	3.1%	0.05	0.011
		Weekends & Holidays	Off-Peak	2.25	0.6%	0.01	0.010
	Non-Summer	Weekdays	Part-Peak	3.09	3.3%	0.10	0.015
			Off-Peak	1.48	4.7%	0.07	0.014
		Weekends & Holidays	Off-Peak	1.94	1.9%	0.04	0.011
Schools	Summer	Weekdays	Peak	4.43	3.4%	0.15	0.121
			Part-Peak	3.08	6.5%	0.20	0.070
			Off-Peak	1.42	8.0%	0.11	0.021
		Weekends & Holidays	Off-Peak	1.62	12.8%	0.21	0.047
	Non-Summer	Weekdays	Part-Peak	2.98	13.0%	0.39	0.090
			Off-Peak	1.76	9.2%	0.16	0.037
		Weekends & Holidays	Off-Peak	1.48	16.7%	0.25	0.027
Wholesale, Transport & Other Utilities	Summer	Weekdays	Peak	2.02	5.7%	0.11	0.010
			Part-Peak	1.57	5.1%	0.08	0.008
			Off-Peak	1.14	-0.3%	0.00	0.009
		Weekends & Holidays	Off-Peak	1.05	5.1%	0.05	0.007
	Non-Summer	Weekdays	Part-Peak	1.63	6.4%	0.10	0.009
			Off-Peak	1.14	1.5%	0.02	0.008
		Weekends & Holidays	Off-Peak	0.99	4.4%	0.04	0.010

The second noticeable feature of the PG&E results is that customers in nearly every industry experienced statistically significant load reductions for all of the TOU rate blocks, including the off-peak period for which the price per kWh became lower. This result suggests that customers responded to the TOU rate by engaging in more efficient behavior overall as opposed to shifting consumption from the peak and semi-peak periods to the off-peak period. The final characteristic of the PG&E results that deserves attention is that percent impacts in the winter are larger than those in the summer for most industries despite the price differentials being higher in the summer. Though seemingly counterintuitive at first, these results are evidence that prices are most likely not the only stimulus responsible for changing behavior. Pricing theory, while useful, sometimes tells only part of the story.[3]

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3 As examples, see the *2013 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs* (April 2014), which contains results showing customers reducing loads when given a price discount and evidence of customers who experience the smallest price differentials (Tier 5 customers non-CARE customers) delivering much, much larger reductions than customers with the largest price ratios (CARE customers).

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There are several possible explanations for why transitioning to a TOU rate would result in decreased usage during all rate periods and larger impacts in the winter, including:

- The transition to TOU increased self-awareness about energy consumption habits overall;

- Customers responded to TOU by using rules of thumb, which may lead to reductions in other time periods;

- Actions that reduce consumption by a fixed amount would be larger in percentage terms during the winter, when total usage is lower;

- The higher prices were in effect between 8:30 AM and 9:30 PM. Customers may have been taking actions to reduce demand over the broader high price period. Actions targeting such a broad period could easily spill over into off-peak hours. Alternatively, given the broad period of higher prices, customers may have consciously elected to reduce consumption;

- The TOU rate transition took place in November and customer response may have been based on the loads that were adjustable at the time;

- Some customers may be responding by installing energy efficiency measures because it is what they know; and

- The response is due to high levels of education/communication, although the fact that it persists for a year with little change undermines this argument for a temporary education boost.

6.4   Standard Errors and Confidence Intervals

The PG&E evaluation involved tens of thousands of customers and a statistically matched control group that was able to produce very precise estimates.[4] By applying these same estimates to SDG&E, we are introducing several new sources of uncertainty that reflect differences between customers in the two territories. These sources include differences in the mix of customers, differences in climate, differences in weather sensitivity, differences in the education and outreach initiatives, and differences in business types within a particular industry. Though it would clearly be wrong to apply the estimated PG&E standard errors as is, there is no good mechanism for determining how they should be adjusted in light of the additional uncertainty. Absent a good strategy for making defensible quantitative adjustments to the standard errors, the best approach is to simply inflate the estimated errors by a sufficiently large factor (we used a factor of 15) to produce confidence intervals that are more likely to reflect the true uncertainty of the estimates than do the very small standard errors from the PG&E evaluation. These errors and confidence bands should not be interpreted as having come from any robust econometric estimation, but are intended to point out the large amount of uncertainty surrounding the point estimates. Due to the lack of empirical data that exists for the relevant population, we see no other feasible approach.

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[4] This is primarily true for the SMB population. Estimates of standard errors for agricultural customers are based on smaller samples and are generally of a more reasonable magnitude when compared directly with the impact estimates.

6.5   Incremental Impacts of CPP Prices

PG&E's impact estimates can be used as the basis for all SPP ex ante load impacts except for one—the peak period impact for CPP event days. Because the PG&E impacts are for a TOU rate, another data source is required to estimate impacts for the high priced peak period on CPP days.[5]

In 2015, PG&E began to default their small commercial customers on to a CPP rate, and measured impacts over the course of 15 events during the summer of 2015. This represents the first evaluation of default CPP for small commercial customers in California. Table 6-3 shows the hourly event impact for these customers for the average event. Because the event window for PG&E only overlapped with that of SDG&E for four hours (PG&E's events run from 2-6pm while SDG&E events run from 11-6pm), the average event impact across all event hours was applied to get small commercial CPP impacts to avoid making assumptions about how the small commercial customers would react over the event duration and at different times of day than their counterparts in the PG&E territory.

Table 6-3: PG&E Default CPP Impacts for Small Commercial Customers

Event Hour	Percent Impact	Percent Standard Error
15	0.17%	0.37%
16	0.50%	0.37%
17	0.64%	0.36%
18	0.72%	0.36%
Average	0.51%	0.37%

Caution should be taken in interpreting these results with any high degree of confidence. The impacts are all within less than two standard errors of zero, indicating that they fail to meet significance thresholds at any conventional level.

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[5] It would be possible to calculate elasticities based on the TOU impacts and apply them to the CPP prices, but this represents an extreme out-of-sample prediction and past experience has shown the resulting estimates to be highly inaccurate.

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7 Ex Ante Load Impact Results

This section presents the results of the ex ante impact evaluation for each class of SDG&E customer that will transition to the SPP rates.

7.1 Small Commercial Customers TOU

Peak period load impact estimates attributable to the TOU component of the SPP rates on a 2016 August system peak day (SDG&E weather conditions) are presented in table 7-1 for each industry. Percent impacts range from -6% for Manufacturing (load increase) to nearly 9% for Agriculture, Mining & Construction. The forecasted aggregate impact for all small commercial customers is about 13.5 MW under 1-in-2 conditions and approximately 7% higher (14.4 MW) under 1-in-10 conditions.

**Table 7-1: Ex Ante TOU Load Impacts for Small Commercial Customers
on August Monthly System Peak Non-Event Day (SDG&E Weather Conditions)**

Industry	SDG&E 1-in-2			SDG&E 1-in-10			% Impact
	Ref Load (kW)	Avg. Impact per Customer (kW)	Aggregate Impact (MW)	Ref Load (kW)	Avg. Impact per Customer (kW)	Aggregate Impact (MW)	
Agriculture, Mining & Construction	2.66	0.23	1.61	2.95	0.26	1.82	8.65%
Manufacturing	5.18	-0.31	-1.42	5.55	-0.33	-1.51	-5.98%
Wholesale, Transport & Other Utilities	3.55	0.2	1.62	3.94	0.22	1.78	5.63%
Retail Stores	4.77	0.05	0.55	5.18	0.06	0.66	1.05%
Offices, Hotels, Finance, Services	3.75	0.12	6.13	4.08	0.13	6.64	3.20%
Schools	4.24	0.15	0.36	4.24	0.15	0.36	3.54%
Institutional/Government	2.37	0.18	4.34	2.37	0.18	4.34	7.59%
Other or Unknown	1.6	0.04	0.31	1.83	0.05	0.39	2.50%
All Small Commercial	**3.40**	**0.12**	**13.54**	**3.66**	**0.12**	**14.44**	**3.43%**

Aggregate impacts for each month of the year are presented in table 7-2. The impacts range from a low of about 9.8 MW in May to a high of almost 16 MW in November. It should be noted that impacts are approximately 30–40% larger in the winter compared to the summer, which is a direct consequence of basing the ex ante estimates on the results from PG&E.

Table 7-2: Aggregate Ex Ante TOU Load Impacts for Small Commercial Customers on Monthly System Peak Non-Event Days

Month	Load Impact (MW)			
	CAISO		SDG&E	
	1-in-2	1-in-10	1-in-2	1-in-10
January	14.20	14.20	14.20	14.20
February	14.04	14.04	14.04	14.04
March	13.81	14.49	13.81	14.26
April	13.40	14.79	13.61	15.18
May	9.85	11.42	10.38	11.85
June	11.26	12.21	11.26	12.24
July	12.21	12.59	12.25	13.42
August	13.79	13.93	13.54	14.44
September	13.66	14.73	13.50	14.61
October	12.50	13.59	12.89	13.99
November	14.44	15.23	14.55	15.68
December	14.20	14.20	14.20	14.20

The forecasted enrollment provided by SDG&E shows an increase in enrollment due to natural account growth over time. As mentioned in the introduction, customers will be defaulted on to a TOU-CPP rate starting in November 2015, with the option to opt out of the CPP component on to a TOU-only rate. Table 7-3 provides aggregate impacts for each August Monthly System Peak Non-Event Day in the forecast according to the SDG&E 1-in-2 Weather Forecast.

Table 7-3: Aggregate Ex Ante TOU Load Impacts for Small Commercial Customers on August Monthly Peak Days

Year	2016	2017	2018	2019	2020	2021-2026
Aggregate Reference Load (MW)	395.29	396.21	396.58	397.02	397.39	397.74
Aggregate Impact (MW)	13.54	13.58	13.59	13.60	13.62	13.63

Figure 7-1 shows the August 2016 monthly system peak day results for a 1-in-2 utility weather scenario on a non-event day. While impacts are positive across all hours, percent impacts are small; on the order of 3-4% compared to the flat rate. Large confidence bands indicate that these results should be interpreted with caution as they cannot be distinguished from zero.

Figure 7-1: Aggregate Ex Ante TOU Load Impacts for Small Commercial Customers on August Monthly Peak Days

San Diego Gas & Electric
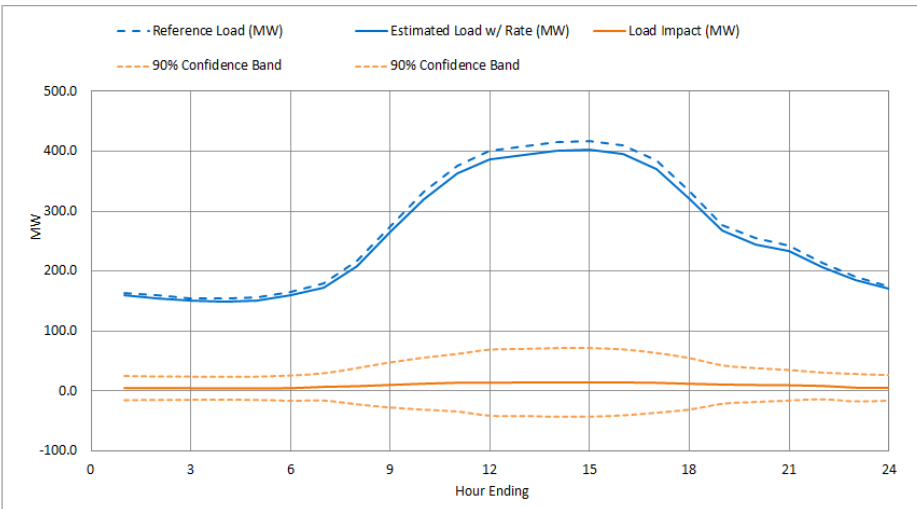2015 Ex Ante Load Impacts - TOU, TOU-CPP

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TABLE 1: Menu Options

Type of Results	Aggregate
Customer Category	All Customers
Weather Conditions	SDGE
Weather Year	1-in-2
Forecast Year	2016
Day Type	MONTHLY SYSTEM PEAK DAY - TOU ONLY
Month	August
Total Enrolled Acoounts	116,119

TABLE 2: Rate Impact Summary

TOU Peak Window Start	11:00 AM
TOU Peak Window End	6:00 PM
Avg. TOU Peak Reduction (MW)	13.54
% TOU Peak Reduction	3.4%
CPP Event Window Start	NA
CPP Event Window End	NA
Avg. Reduction for CPP Event (MW)	NA
% Reduction for CPP Event	NA

Hour Ending	Reference Load (MW)	Estimated Load w/ Rate (MW)	Load Impact (MW)	% Load Reduction	Weighted Temp. (F)	Uncertainty-Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	163.92	159.37	4.54	2.77%	71.25	-15.62	-3.71	4.54	12.80	24.71
2	158.82	154.41	4.41	2.78%	71.46	-15.22	-3.62	4.41	12.44	24.04
3	155.01	150.71	4.31	2.78%	70.81	-15.02	-3.60	4.31	12.21	23.63
4	153.47	149.21	4.26	2.78%	70.63	-14.91	-3.58	4.26	12.11	23.44
5	155.27	150.99	4.28	2.75%	70.43	-15.15	-3.67	4.28	12.22	23.70
6	164.95	160.49	4.46	2.70%	69.91	-16.73	-4.21	4.46	13.13	25.65
7	179.52	172.99	6.53	3.64%	70.03	-16.28	-2.81	6.53	15.86	29.33
8	216.63	208.97	7.66	3.54%	69.70	-22.60	-4.72	7.66	20.05	37.93
9	275.42	265.61	9.81	3.56%	71.28	-27.95	-5.64	9.81	25.27	47.58
10	331.92	320.00	11.92	3.59%	73.95	-31.59	-5.88	11.92	29.72	55.43
11	375.78	362.29	13.49	3.59%	77.43	-34.50	-6.15	13.49	33.13	61.48
12	400.03	386.44	13.60	3.40%	79.94	-41.63	-9.00	13.60	36.20	68.82
13	408.43	394.57	13.86	3.39%	81.36	-42.22	-9.09	13.86	36.81	69.94
14	415.64	401.59	14.05	3.38%	82.07	-43.25	-9.39	14.05	37.50	71.36
15	417.74	403.56	14.18	3.39%	81.62	-43.11	-9.27	14.18	37.62	71.47
16	409.26	395.22	14.04	3.43%	81.40	-41.02	-8.49	14.04	36.57	69.10
17	383.90	370.52	13.38	3.48%	80.71	-36.52	-7.04	13.38	33.79	63.27
18	331.99	320.28	11.71	3.53%	79.84	-31.34	-5.91	11.71	29.32	54.76
19	277.36	266.91	10.44	3.76%	77.15	-21.51	-2.63	10.44	23.51	42.39
20	254.82	245.10	9.72	3.82%	75.87	-18.47	-1.81	9.72	21.26	37.92
21	242.73	233.43	9.29	3.83%	74.11	-16.25	-1.16	9.29	19.74	34.83
22	214.30	206.15	8.15	3.80%	73.30	-14.09	-0.95	8.15	17.25	30.39
23	189.76	184.51	5.26	2.77%	72.63	-17.71	-4.14	5.26	14.66	28.22
24	174.62	169.80	4.82	2.76%	72.53	-16.52	-3.91	4.82	13.55	26.16

	Reference Energy Use (MWh)	Estimated Energy Use w/ rate (MWh)	Total Load Impact (MWh)	% Load Change	Cooling Degree Hours (Base 60)	Uncertainty-Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily (MWh)	6,451.3	6,233.1	218.2	3.4%	359.4	35.14	143.28	218.17	293.06	401.20
TOU Peak (MWh)	2,767.0	2,672.2	94.8	3.4%	147.0	-47.08	36.75	94.81	152.88	236.71

Note: A positive value % Daily Load Change indicates the use of less energy for the day.

Chart legend: Reference Load (MW); Estimated Load w/ Rate (MW); Load Impact (MW); 90% Confidence Band; 90% Confidence Band. Y-axis: MW (−100.0 to 500.0). X-axis: Hour Ending (0 to 24).

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7.2 Small Commercial Customers TOU-CPP

Results for the incremental impact of a CPP rate on event days was estimated from PG&E's default small commercial program starting in 2015. Estimates of impacts were small and failed to meet significance thresholds at conventional levels. The results presented here should be interpreted with caution.

Peak period load impact estimates attributable to TOU-CPP SPP rates on a 2016 August system peak day (SDG&E weather conditions) are presented in table 7-4 for each industry. Percent impacts range from -5.5% for Manufacturing (load increase) to nearly 9.3% for Agriculture, Mining & Construction. The forecasted aggregate impact for all small commercial customers is about 14.2 MW under 1-in-2 conditions and approximately 7% higher (15.2 MW) under 1-in-10 conditions.

Table 7-4: Ex Ante TOU-CPP Load Impacts for Small Commercial Customers on August Monthly System Peak Event Day (SDG&E Weather Conditions)

Industry	SDG&E 1-in-2			SDG&E 1-in-10			% Impact
	Ref Load (kW)	Avg. Impact per Customer (kW)	Aggregate Impact (MW)	Ref Load (kW)	Avg. Impact per Customer (kW)	Aggregate Impact (MW)	
Agriculture, Mining & Construction	2.66	0.25	1.58	2.95	0.27	1.75	9.28%
Manufacturing	5.18	-0.29	-1.20	5.55	-0.31	-1.29	-5.52%
Wholesale, Transport & Other Utilities	3.55	0.22	1.63	3.94	0.24	1.81	6.19%
Retail Stores	4.77	0.08	0.79	5.18	0.08	0.85	1.63%
Offices, Hotels, Finance, Services	3.75	0.14	6.57	4.08	0.15	7.15	3.75%
Schools	4.24	0.17	0.37	4.24	0.17	0.37	3.96%
Institutional/Government	2.37	0.19	4.17	2.37	0.19	4.17	7.98%
Other or Unknown	1.60	0.05	0.34	1.83	0.05	0.39	2.98%
All Small Commercial	**3.40**	**0.13**	**14.24**	**3.66**	**0.14**	**15.20**	**3.94%**

Aggregate impacts for each month of the year are presented in table 7-5. The impacts range from a low of about 10.4 MW in May to a high of almost 16 MW in September. It should be noted that impacts are approximately 30–40% larger in the winter compared to the summer, which is a direct consequence of basing the ex ante estimates on the results from PG&E.

Table 7-5: Aggregate Ex Ante TOU Load Impacts for Small Commercial Customers on Monthly System Peak Event Days

Month	Load Impact (MW)			
	CAISO		SDG&E	
	1-in-2	1-in-10	1-in-2	1-in-10
January	13.40	13.40	13.40	13.40
February	13.24	13.24	13.24	13.24
March	13.02	13.68	13.02	13.46
April	12.65	13.98	12.85	14.35
May	10.36	12.05	10.93	12.52
June	11.85	12.87	11.84	12.90
July	12.84	13.25	12.87	14.13
August	14.50	14.65	14.24	15.20
September	14.38	15.52	14.21	15.39
October	13.11	14.29	13.53	14.72
November	13.63	14.39	13.74	14.82
December	13.40	13.40	13.40	13.40

Enrollment in the TOU-CPP rates is forecast to decrease over time. This is because SDG&E forecasts a larger fraction of customers switching to TOU-only rates over time and away from the TOU-CPP rate. Despite a growing population, enrollment will decrease over time, flattening out after 2019.

Table 7-6: Aggregate Ex Ante TOU-CPP Load Impacts for Small Commercial Customers on August Monthly Peak Days

Year	2016	2017	2018	2019-2026
Aggregate Reference Load (MW)	361.77	323.75	304.74	304.74
Aggregate Impact (MW)	14.24	12.74	12.00	2.00

Figure 7-1 shows the August 2016 monthly system peak event day results for a 1-in-2 utility weather scenario. While impacts are positive across all hours, percent impacts are small; on the order of 3-4% compared to the flat rate, of which 0.5% is attributed to the effect of a CPP event during event hours. Large confidence bands indicate that these results should be interpreted with caution as they cannot be distinguished from zero.

Figure 7-2: Aggregate Ex Ante TOU-CPP Load Impacts for Small Commercial Customers on August Monthly Peak Event Days

San Diego Gas & Electric
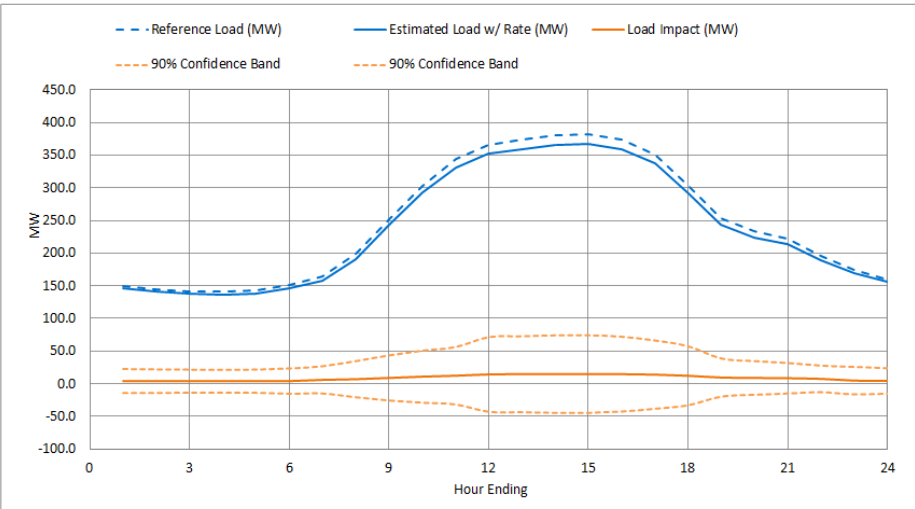2015 Ex Ante Load Impacts - TOU, TOU-CPP

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TABLE 1: Menu Options

Type of Results	Aggregate
Customer Category	All Customers
Weather Conditions	SDGE
Weather Year	1-in-2
Forecast Year	2016
Day Type	MONTHLY SYSTEM PEAK DAY - CPP EVENT DAY
Month	August
Total Enrolled Acoounts	106,274

TABLE 2: Rate Impact Summary

TOU Peak Window Start	11:00 AM
TOU Peak Window End	6:00 PM
Avg. TOU Peak Reduction (MW)	14.24
% TOU Peak Reduction	3.9%
CPP Event Window Start	11:00AM
CPP Event Window End	6:00PM
Avg. Reduction for CPP Event (MW)	14.24
% Reduction for CPP Event	3.9%

Hour Ending	Reference Load (MW)	Estimated Load w/ Rate (MW)	Load Impact (MW)	% Load Reduction	Weighted Temp. (F)	Uncertainty-Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
1	150.02	145.86	4.16	2.77%	71.25	-14.29	-3.39	4.16	11.71	22.61
2	145.35	141.32	4.04	2.78%	71.46	-13.93	-3.32	4.04	11.39	22.00
3	141.87	137.93	3.94	2.78%	70.81	-13.75	-3.30	3.94	11.18	21.63
4	140.46	136.56	3.90	2.78%	70.63	-13.65	-3.28	3.90	11.08	21.45
5	142.11	138.19	3.91	2.75%	70.43	-13.86	-3.36	3.91	11.19	21.69
6	150.96	146.88	4.08	2.70%	69.91	-15.31	-3.85	4.08	12.02	23.47
7	164.30	158.33	5.97	3.64%	70.03	-14.90	-2.57	5.97	14.51	26.84
8	198.26	191.25	7.01	3.54%	69.70	-20.69	-4.32	7.01	18.35	34.71
9	252.07	243.09	8.98	3.56%	71.28	-25.58	-5.16	8.98	23.13	43.55
10	303.78	292.87	10.91	3.59%	73.95	-28.91	-5.39	10.91	27.20	50.73
11	343.92	331.57	12.35	3.59%	77.43	-31.58	-5.63	12.35	30.32	56.27
12	366.12	351.81	14.31	3.91%	79.94	-42.87	-9.09	14.31	37.71	71.49
13	373.81	359.21	14.59	3.90%	81.36	-43.55	-9.20	14.59	38.38	72.73
14	380.41	365.60	14.80	3.89%	82.07	-44.57	-9.49	14.80	39.10	74.17
15	382.32	367.40	14.93	3.90%	81.62	-44.49	-9.39	14.93	39.24	74.34
16	374.57	359.80	14.76	3.94%	81.40	-42.56	-8.70	14.76	38.22	72.09
17	351.35	337.32	14.03	3.99%	80.71	-38.31	-7.38	14.03	35.45	66.37
18	303.84	291.58	12.26	4.04%	79.84	-32.92	-6.22	12.26	30.75	57.44
19	253.84	244.29	9.56	3.76%	77.15	-19.69	-2.41	9.56	21.52	38.80
20	233.22	224.32	8.90	3.82%	75.87	-16.90	-1.66	8.90	19.46	34.70
21	222.15	213.64	8.50	3.83%	74.11	-14.87	-1.06	8.50	18.07	31.88
22	196.13	188.67	7.46	3.80%	73.30	-12.90	-0.87	7.46	15.79	27.82
23	173.68	168.86	4.81	2.77%	72.63	-16.21	-3.79	4.81	13.41	25.83
24	159.82	155.40	4.41	2.76%	72.53	-15.12	-3.58	4.41	12.40	23.94

	Reference Energy Use (MWh)	Estimated Energy Use w/ rate (MWh)	Total Load Impact (MWh)	% Load Change	Cooling Degree Hours (Base 60)	Uncertainty-Adjusted Impact - Percentiles				
						10th	30th	50th	70th	90th
Daily (MWh)	5,904.4	5,691.8	212.6	3.6%	359.4	31.03	138.30	212.59	286.89	394.16
CPP (MWh)	2,532.4	2,432.7	99.7	3.9%	147.0	-47.86	39.31	99.69	160.07	247.24

Note: A positive value % Daily Load Change indicates the use of less energy for the day.

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8 Conclusions and Recommendations

An ex post analysis of the load impacts associated with the voluntary SPP rates in the summer of 2015 showed no statistically significant reductions in peak period usage and the majority of evidence suggests that customers viewed the SPP rates as a way to reduce their electricity costs without needing to change their consumption behavior. Due to the unique set of customers who enrolled on the rates, however, these results cannot be used as the basis for ex ante estimation for the SDG&E small commercial population as a whole.

As discussed throughout the report, the ex ante load impact estimates presented here are necessarily based on borrowed data. The estimates for TOU are based on default TOU impacts for PG&E's customer population for a mandatory rate where customers could not opt-out to an alternative rate option. SDG&E is planning to default customers onto TOU-CPP, but will give them the option of changing to a TOU rate. As such, there is a good deal of uncertainty in the estimates presented here.

Even after SDG&E deploys default TOU rates for the small commercial population in its own service territory, it will be difficult if not impossible to estimate ex post load impacts unless SDG&E implements the plan in stages so there is a period of time when some customers are on the new rates and others are not. Alternatively, SDG&E could hold back a small control group of customers who stay on the standard rate for a period of time for the sole purpose of measuring impacts. In either case, it is critical that the customers who remain on the non-time varying rate for some period of time be randomly chosen. Put another way, if SDG&E does a phased roll out of the default rate, it's important that customers who are assigned the new rate and those that are delayed are identical except that one is on the rate and the other isn't. If the phased roll out is done on some other basis (e.g., geographically, by size stratum, etc.), it will be much more difficult and, perhaps, impossible to estimate impacts with any degree of accuracy.

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